SNC•LAVALIN T&D

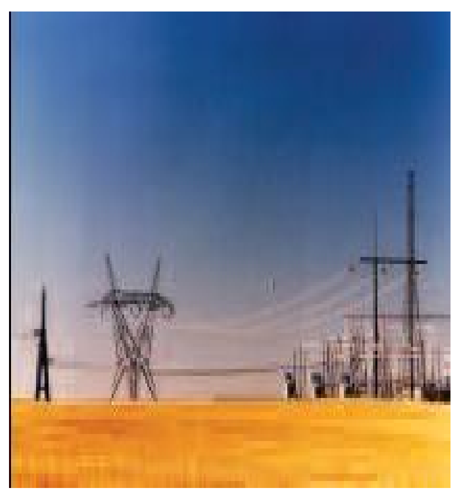
Final Report

Transmission and System Operator Options for Nova Scotia

Prepared for

Nova Scotia Department of Energy

December 2009



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NOTICE

Executive Summary

The Government of Nova Scotia, through the Department of Energy (NS-DOE), contracted SNC-Lavalin to undertake an independent Transmission and System Operator Study (T&SO Study) to identify and assess the opportunities and challenges of an expanded provincial and regional transmission system; and to identify and assess various system operator alternatives. The main focus of the T&SO Study was to review, develop and assess the Province's public policy options for future transmission and system operator activities and decisions. This report contains the study findings, conclusions and recommendations. Resource scenarios were obtained from the 2009 IRP update that is in progress. Options for expanding the transmission system were obtained from reports and discussions with the various stakeholders.

1. Transmission Options

An overview of the demand, environmental considerations, generation resources and options and related transmission options was carried out for Nova Scotia and for the regional electric system including New Brunswick, PEI, Québec, Newfoundland and Labrador and New England. Major changes are forecast in these power systems with the development of major new renewable power developments in the next few years and beyond. Demand Side Management programs are expected to result in lower load growth rate.

This report covers three time frames:

- The short term time frame, from present to 2012, which examines the existing transmission system reliability and the impact of integrating renewable resources to meet 2010 Renewable Energy Standard (RES) and 2010 Green House Gas (GHG) emission cap requirements;

- The medium term timeframe, which discusses the prospects of transmission system development five years out; and the transmission system requirements to maintain reliable system operation and to integrate renewable resources to meet 2013 RES and 2015 GHG emission caps; and

- The longer term time frame, 2015 to 2020 and beyond, which discusses the prospects of the transmission system to meet integration of renewable resources to meet the 2015 renewable target and 2020 GHG emission caps and development of domestic and regional resources which facilitate large scale export and import of renewable energy.

The analysis provides a high level "snapshot" of the potential transmission options and is not a transmission system plan. All transmission facilities and estimated associated costs are indicative figures presented only to facilitate understanding of the level of capital needed to realize such potential transmission options. Transmission plans will depend on the pace of evolution of generation resources, load growth rates, demand side management initiatives, as well as development in neighbouring jurisdictions.

The transmission requirements for the mid to longer term will depend primarily upon the resource development as a result of aggressive government GHG policies in Nova Scotia and the region including New England. The Atlantic provinces, "Nova Scotia, New Brunswick, Prince Edward Island, and Newfoundland and Labrador", are blessed with ample sources of renewable resources. New England and the U.S.A in general will need such resources in the mid to longer term. Potential transmission schemes for major power transfers have been outlined and evaluated in this report. However, major regional planning and operating studies are required to fully understand the requirements of such power systems.

These four major transmission concepts were evaluated for the medium and long term resource scenarios:

- A Second Intertie with New Brunswick which would be required in the long term (after 2015), but could be advanced to medium term (around 2013);
- Nova Scotia internal transmission links to facilitate renewable resources, mainly eastern wind power development in the long term scenarios, with potential major wind power developments for exports;
- Importing transmission link from Newfoundland (+/- 450 HVDC submarine cable & overhead line) that would be required for power imports from the Lower Churchill hydro project; and
- Direct submarine cable from southern Nova Scotia to New England (+/- 450 HVDC submarine cables) for potential exports to load centres in New England.

Key Findings:

The following findings are applicable for the present transmission system:

- Minor transmission reinforcements for the strengthening of the Nova Scotia system in the near future have been identified and it is expected that the NS system can be operated reliably within the current security criteria. An issue that remains is the increasing loading of the interties and albeit small risks of widespread load shedding under tie line outage in some cases.
- In the short term, the Nova Scotia system can be operated reliably within the security limits of the existing transmission interfaces with the addition of the new wind generation facilities. This may require a change in the economic dispatch principles presently in use.
- Dynamic thermal ratings (using physical monitoring equipment where required for specific limited transmission lines) can release more transfer capacity to evacuate wind power on the existing transmission infrastructure.

The following findings are applicable for medium to long transmission system development (2013 and beyond):

- Wind power will likely be the main resource that will be developed to meet the 2013 RES and proposed Green House Gas emission targets, which may result in an installed capacity of 581 MW of Wind Power by 2013. The operational implications of this level of wind must be fully understood by detailed study.

- The Nova Scotia Wind Integration study was an indicative study, as the study did not consider the uncertainty of wind power. More study is needed to capture and deal with this issue. Nova Scotia System islanding with large amounts of wind generation imposes greater risk of utilization of load shedding. A second intertie would mitigate such risks. Concurrent system reinforcement on the New Brunswick system would be necessary.

- Increased level of wind penetration may result in dispatching available resources ignoring the merit order, and will lead to a dispatch pattern which is more complicated and expensive.

- Wind Power should be developed in locations that do not increase current system stresses, or trigger uneconomic transmission needs – potential locations have been identified in this report but these locations will need to be pin-pointed by further study. The impact of the increasing amounts of wind penetration on system operation and further reliance on the tie lines must be studied in more detail. Joint planning studies are recommended so that the configuration, costs and benefits of a second 345 kV tie are fully understood by all parties if the tie line needs to be implemented.

- Achieving stringent GHG targets may require strengthened NS interties with other jurisdictions. These interties would facilitate trading renewable energy and would strengthen the reliability of the transmission system. A second intertie development with New Brunswick would cost in the range of $200-250 Million; this cost does not include required reinforcement on NB side. Intertie costs from Newfoundland range from $800 Million to $1.2 Billion; this cost does not include reinforcement in Newfoundland. The cost of a major undersea intertie with load centres in New England (NE) would range from $2.0 to $3.0 Billion; this cost does not include possible reinforcement required in NE. These figures are indicative costs. Further pre-feasibility and feasibility studies will be needed to understand accurate costs associated with these developments and to establish the technical feasibility of these transmission options.

Next Steps:

- A study should be undertaken to quantify the benefit of the use of dynamic thermal rating in Nova Scotia. This should be thought of as an operational measure until system reinforcement is in place.
- Identify the locations with the combination of the best wind regimes and low transmission costs, and promote wind power development in those areas.
- Joint studies are required with New Brunswick regarding transmission upgrade in the Moncton/Salisbury area to support area loads and the reliable operation of a potential second 345 kV intertie between New Brunswick and Nova Scotia.
- Gain the advantages of advancing the additional Nova Scotia tie-line to the medium term. Establish the best configuration, technology and transmission requirements, costs and schedule of the additional tie-line, including regional requirements.
- Major strategies for development of major regional clean resources and export to the USA are in the realm of the provincial energy and economic policy. It is recommended that a Maritime Regional Transmission Planning function be implemented to study and plan transmission system requirements on a regional basis for attaining mutual benefits over the long term.

2. System Operator Options

A review was made of the shifts in electricity policy and regulation in Canada and especially in the Maritime region in the last few years. In turn, these shifts have impacted the restructuring of the electricity sectors in several provinces and have brought about increased competition in the wholesale supply and retail functions. It is within this context, and the potential evolution from the current situation in Nova Scotia and in the Maritimes Region, that the new roles of the system operator were analyzed.

This report was prepared independent of, and prior to, New Brunswick's proposed sale of electricity system assets to Hydro-Québec. While this may certainly influence Nova Scotia's future direction, this report does not evaluate the proposed deal or its potential impacts. Any potential impacts will depend on whether the merger goes ahead, and what the final details are.

Four different possible scenarios for the evolution of the system operator in Nova Scotia were assessed, including the scenario to remain as it is today. The four options evaluated included:

Option 1 - Current Functionally Unbundled NSPSO - under the current arrangement, the Nova Scotia Power System Operator functions as part of the NSPI Customer Operations Division. NSPSO carries on its obligations following the standards of conduct approved by

UARB, ensuring that market sensitive information is not intentionally or inadvertently shared among other groups within NSPI, particularly the transmission and the wholesale merchant groups.

Option 2 - Independent NS system Operator (NSISO) - to make the NSISO completely independent of any market participant and transmission owner. The NSISO would be created by provincial legislation and regulated by the UARB as a non-profit organization.

Option 3 - NS/NB-ISO - creation of a new entity responsible for jointly operating the bulk electricity systems and wholesale markets in both provinces. The Nova Scotia operator would need to be made independent of NSPI in order to be amalgamated with the already independent NBSO.

Option 4 - Regional ISO - without a major change, a regional ISO is a medium to long-term alternative.

The options were evaluated and ranked after consultations with stakeholders, a review of existing studies, consultations with other system operators and review of regulatory requirements.

Key Findings:

From the market perspective IPPs have only a single buyer market in each Maritime province and a transmission rights market at interties that is subject to the exercise of market power by a few large entities. The only competition that can occur in such a situation is therefore the “competition on entry” to build new generating plants for serving in-province needs.

The independence of the SO becomes more important as the regional market becomes more accessible to Nova Scotia, and because an independent SO will have objectives which are unconditioned by corporate ownership, it could champion regional market changes on behalf of Nova Scotia. Provincial interests can only be unambiguously represented by an SO that is independent of all market participants, and has a mandate and governance structure that reflects the public interest. Also, as new players invest in new renewable generation in Nova Scotia, the system planning functions (generation and transmission) currently performed by NSPSO may need to be reviewed, to ensure there is a level playing field and that provincial interests are met.

Economies of scale mean that there will inevitably be some advantages to integrating system operations throughout the Maritimes and beyond. Option 3 (combining SO for NS and NB) or Option 4 (regional SO) could be the next steps after Option 2 (standalone NS SO), or each could be a direct transition from the existing Option 1.

While Option 3 has clearly been the objective of NBSO and New Brunswick has adopted a strategic goal of becoming an energy hub, provincial representatives from New Brunswick have in effect defended the existing system of pancaked transmission tariffs, which undermines the value of Option 3. The proposed merger raises further questions about the future of the energy hub objective and therefore the feasibility for Options 3 and 4 from Nova Scotia’s perspective.

Possible impetus might come from one of the two major projects under discussion whose justification requires access to a regional market – expansion of the Point Lepreau nuclear generating plant, or a Maritimes routing for transmission from the Lower Churchill project in Labrador. Either of these projects will inherently involve discussions among several provincial governments which could expand to include a regional scope for the electricity market and system operations.

In moving beyond Option 2, Nova Scotia would have to see some assurances of improved access to both supply and markets outside the province. While arrangements for transmission access are fundamental to any competitive electricity market, they become particularly critical when interconnections to neighbouring systems are involved. Transmission access, and arrangements to prevent the exercise of market power through limiting transmission access, therefore become increasingly important when considering moving beyond Option 2.

Next Steps:

Discussions and policy definitions regarding the future scope of the electricity market in Nova Scotia, and to some extent in the whole Maritimes region, are needed before committing to a change in the SO arrangements for Nova Scotia.

Some key aspects that need to be considered in the discussions of a regional electricity market for the Maritime region were identified as:

- Possibility of a regional approach to just wind integration as a first step towards a more comprehensive regionalization
- Improved access to regional interconnections by preventing the exercise of market power in allocating transmission capacity
- Elimination of rate pancaking
- Change to a public-good transmission concept

Nova Scotia also needs to play an active role in the discussions regarding new large-scale generation and transmission developments in the Maritime region, making sure that the interests of Nova Scotians are served in terms of pricing, reliability, security of supply and environmental sustainability.

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1. Introduction

1.1 Background

The Government of Nova Scotia, through the Department of Energy (NS-DOE), contracted SNC-Lavalin to undertake an independent Transmission and System Operator Study (T&SO Study) to identify and assess the opportunities and challenges of an expanded regional transmission system; and to identify and assess various system operator alternatives. The main focus of the T&SO Study is to develop and assess the Province's public policy options for future transmission and system operator activities and decisions. The study objectives and report organization are outlined below.

1.2 Objective & Scope

The T&SO Study focuses primarily on the transmission components of the electricity system in Nova Scotia. It is not defined as a "technical or detailed operational study", but rather a comprehensive identification of options, high-level analysis of these options, and development of conclusions and recommendations as to specific options recommended for further detailed analysis and possible policy direction. It also includes costs, benefits, risks and required partnerships or relationships to successfully implement these actions.

As described in the Scope of Work, the T&SO study includes the following areas:

1. A review of the options to enhance, expand and strengthen the transmission system within Nova Scotia to ensure the required standards of system reliability are being met, and will continue to be met, both for internal supply and any interconnected power transactions.

2. A review of the options to expand the transmission system within Nova Scotia to accommodate, in an efficient and least-cost manner, planned and future renewable energy supplies (wind, tidal, biofuels, hydro, etc.) that are a very important component of the Province's environmental and air emissions targets as stated in the 2007 "Environmental Goals and Sustainable Prosperity Act (EGSPA"). The study will examine options to expand the transmission system for potential "larger wind and tidal renewable power" development opportunities, including any required expansion of interconnection capacity between Nova Scotia and New Brunswick for the import and/or export of additional electricity from those two provinces, and also potential power transactions with Prince Edward Island, the Northeast United States, Québec, and Newfoundland and Labrador.

3. A review of the various options for "system operations management" of Nova Scotia's electricity system including:

a) the existing Nova Scotia Power System Operator (“NSPSO”) which is a functionally separate operation within the NSPI organization;
b) creating a Nova Scotia provincial independent system operator (“NS-ISO”);
c) integration of NSPSO with the New Brunswick System Operator (“NBSO”), and
d) creating a new Regional Independent System Operator (“Regional-ISO”) that initially covers at least Nova Scotia, New Brunswick and Prince Edward Island.

1.3 Methodology

The study was conducted in two phases. In Phase One, the study team collected stakeholder input and feedback regarding transmission and system operation options. The study team also reviewed, assessed, and analysed the previous completed and ongoing transmission-related studies.

Based on the stakeholder feedback and transmission-related studies, the team identified the transmission and system operation options.

Analysis of the available options was initiated by developing evaluation criteria and benchmarks. Acknowledging that this is not a detailed technical study, and the fact that some information and data required for the evaluation criteria was not available to the study team from previous studies, the study team used its best judgment to evaluate these options, and to identify the conditions and triggers which would render these options achievable and attractive to develop.

The study includes the input from the 2009 Integrated Resource Plan (IRP), which is being prepared by NSPI in parallel with this study, and the 2009 updated 10 year transmission outlook which was developed by the Nova Scotia Power System Operator (NSPSO).

1.4 Report Organization

Section 1 of the report presents general background information about the study, the study objectives and methodology followed to achieve these objectives.

Section 2 presents an overview of the electric power system in Nova Scotia and potential renewable generation resources which can be developed. In addition, the transmission system constraints which limit the extent of development of these renewable generation resources are discussed.

The transmission system and operation options presented in this study are greatly influenced by the regional electricity system in the Canadian Maritimes and New England. Several transmission operational and physical constraints which affect the T&SO study alternatives are presented in Section 3.

Increased dependence on energy imports from outside Nova Scotia, and the expected increase in wind energy penetration to meet 2010 RES and GHG emission caps, could erode the reliability of the Nova Scotia bulk transmission system. Options to enhance, expand, and strengthen the transmission system within Nova Scotia, to ensure the required standards of system reliability will be met, are analyzed and presented in Section 4.

To achieve the Nova Scotia Renewable 2013 RES and 2015 renewable target and 2020 GHG emission caps, a high level of wind power may be integrated into the transmission system after 2012, in comparison with the current size of the Nova Scotia electricity market. Nova Scotia has access to favourable wind regimes, which could be further developed under certain enabling conditions to meet the RES and the GHG emissions caps in neighbouring jurisdictions via exports.

Biomass is another resource which Nova Scotia can tap into to achieve the RES and GHG emissions caps. This can be done by building new generation plants which use biomass to generate electricity, or by converting some of the existing coal generation units to burn biomass based fuel (wood pellets, grasses, vegetation waste), or co-firing biomass with coal.

Currently, Nova Scotia is exploring the possibility of employing tidal power on a commercial scale. If the demonstration phase(s) support the viability of tidal power for commercial scale application, Nova Scotia would have the opportunity to generate a large amount of tidal power.

Regionally, the plans for development of hydraulic power at Lower Churchill and nuclear power from a second/third reactor at Point Lepreau, may give Nova Scotia access to imported energy with competitive prices and attractive environmental attributes. Depending how the energy policies and market evolve, Nova Scotia could be a net importer, self sustained or a net exporter for electric energy. To unleash all the possible reliability, import, and export benefits from transmission development within Nova Scotia, the development of transmission facilities within Nova Scotia should be paralleled with transmission system development in neighbouring jurisdictions. This will enable overcoming physical transmission barriers which may exist between the energy sources and the ultimate customers. Section 5 discusses the transmission facilities which would be required under these scenarios.

The current role of the NSPSO has evolved from the context of the reforms to the electricity sector in the province, as well as developments in New Brunswick and the United States. Although the US Federal Energy Regulatory Commission (FERC) has no jurisdiction in Canada, wholesale market opening mandated by FERC Orders 888-889 has been interpreted by Canadian utilities to impose specific obligations on companies who wish to use the open-access US transmission system. Specifically, those companies who wish to use FERC-regulated US transmission networks for energy sales must make reciprocal arrangements to provide open non-discriminatory access to third parties. Some stakeholders have suggested changes to the industry structure in Nova Scotia to make NSPSO more clearly independent from NSPI. Changes to the industry structure may also be beneficial in giving effect to changes in provincial electricity policy or the regional context, for example, decisions made by Nova Scotia and others to develop large regional projects and increase the penetration of renewable energy (particularly wind). It is in this context that the four options contemplated for evolution of system operations are discussed in Section 6.

2. Overview of Nova Scotia's Electric System

2.1 Introduction

This section presents an overview of the existing electric system, with emphasis on existing transmission infrastructure and the system operator which serves Nova Scotia. Nova Scotia Power Inc. (NSPI) is the main service provider responsible for supplying approximately 97% of the energy demand, and also responsible for operation of the transmission and distribution system in the province. NSPI is a subsidiary of Emera Inc. NSPI is a vertically integrated investor-owned utility, regulated by the Nova Scotia Utility and Review Board (UARB). The major facilities of the NSPI bulk transmission system are shown in Figure 2-3.

2.2 Load Forecast and Demand Side Management

2.2.1 Load Forecast

Planning activities for the Nova Scotia electricity system include load forecasting, resource planning, and transmission system planning, and each of these activities are carried out by separate and independent departments of NSPI. As noted in the 10 Year System Outlook document, the NSPI load forecast is based on the analysis of a number of variables which include: sales history, economic indicators, weather conditions, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources. The forecast energy and typical load shapes for consumer classes are used to predict the peak demand.

Table 2-1 shows historical and forecast total annual energy requirements. Peak demand in Nova Scotia occurs in the winter time due to a variety of winter-peaking end-uses such as electric heating. Table 2-2 provides the forecast system peak with and without non-firm peak load.

Table 2-1 Total Energy Requirements (Source: 2009 Load Forecast)

Year	Net System Requirement GWh	Growth Rate %
2001	11,303	0.6
2002	11,501	1.8
2003	12,009	4.4
2004	12,388	3.2
2005	12,338	-0.4
2006	10,946	-11.3
2007	12,639	15.5
2008	12,539	-0.8
2009F	12,478	-0.5
2010F	12,547	0.6
2011F	12,615	0.5
2012F	12,725	0.9
2013F	12,821	0.8
2014F	12,918	0.8
2015F	13,007	0.7
2016F	13,082	0.6
2017F	13,156	0.6
2018F	13,241	0.6

Note:
Actual growth rates for 2006 and 2007 were -11.3 percent and 15.5 percent respectively, which reflects that one of NSPI's largest customers had a temporary shutdown and remained closed for nine months in 2006. For 2007 the plant returned to normal full load operations.

Table 2-2 Coincident Peak Demand (Source: 2009 Load Forecast)

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2009	6.6	412	33.3	1597	1.3
2001	1988	-1	369	-10.4	1619	1.4
2002	2078	4.5	348	-5.7	1730	6.9
2003	2074	-0.2	291	-16.4	1783	3.1
2004	2238	7.9	377	29.6	1861	4.4
2005	2143	-4.2	392	4.0	1751	-5.9
2006	2029	-5.3	386	-1.5	1644	-6.1
2007	2145	5.7	381	-1.3	1764	7.3
2008	2192	2.2	352	-7.5	1840	4.3
2009F	2219	1.2	360	2.2	1859	1.0
2010F	2219	0.0	360	0.1	1858	0.0
2011F	2230	0.5	363	0.6	1867	0.5
2012F	2249	0.9	366	0.8	1883	0.9
2013F	2266	0.8	368	0.7	1898	0.8
2014F	2284	0.8	371	0.7	1913	0.8
2015F	2300	0.7	373	0.6	1927	0.7
2016F	2313	0.6	375	0.6	1938	0.6
2017F	2327	0.6	377	0.6	1949	0.6
2018F	2343	0.7	379	0.6	1963	0.7

2.2.2 Demand Side Management

Demand Side Management (DSM) may be defined as a deliberate effort to decrease, shift or increase energy demand. Utilities develop DSM programs to encourage customers to enact DSM measures. These programs modify customer demand for electricity, helping defer the need for new energy and capacity supply additions. Conservation and energy efficiency can be considered as part of Demand Side Management programs.

Demand Side Management is a main element of the IRP 2007 Reference Plan and will continue to be a key element in the revised IRP which is expected by late 2009. The Nova Scotia Government is in the process of establishing an independent Electricity DSM agency which will cooperate with NSPI and other market participants to achieve DSM goals. Table 2-3 presents the DSM forecast as used in IRP 2009.

Table 2-3 DSM Forecast (Source: IRP 2009 IRP Updated Assumptions)

Totals	25 Year Total	Year 1 (2008)	Year 2	Year 3	Year 6	Year 10 (2017)	Year 15	Year 20	Year 25
Demand Savings (MW)		2.1	6.8	16.9	63.5	55.8	49.6	45.5	43.0
Cumulative (MW)	1106	2.1	8.9	25.8	164.2	392.1	651.6	886.5	1105.7
Energy Savings (GWh)		16.1	50.3	82.7	305.3	268.4	238.2	217.4	204.0
Cumulative (GWh)	5317	16.1	66.3	149.0	804.9	1900.7	3147.5	4272.8	5317.0

As noted in the 10 Year System Outlook document, DSM development in Nova Scotia remains in its early stages. Work has not been undertaken to assign the forecast demand and energy reductions to particular areas of the province. For transmission planning purposes, the long-term effect of DSM remains to be determined.

2.3 Environmental Considerations

2.3.1 GHG Emission Caps

The Environmental Goals and Sustainable Prosperity Act calls for reductions in provincial GHG emissions by at least 10% from 1990 levels by 2020. The Climate Change Action Plan and the Department of Energy's 2009 Energy Strategy details the tools required to achieve this target.

Nova Scotia Power relies heavily on coal and oil to generate electricity and is responsible for about 50% of the province's total greenhouse gas emissions which is equivalent to 10 million tonnes.

Under the GHG emission caps regulation NSPI is expected to cap the GHG emission as follows:

- 2010 GHG emission cap: caps the maximum amount of emissions at 9.7 million tonnes, compared to about 10 million in 2007
- 2015 GHG emission cap: caps the maximum amount of emissions at 8.8 million tonnes
- 2020 GHG emission cap: caps the maximum amount of emissions at 7.5 million tonnes, which represents a reduction of about 25% from the 2007 emission level.

2.3.2 Renewable Energy Standards

The Renewable Energy Standard (RES) was identified in Nova Scotia's Climate Change Action Plan as one of the actions required to achieve the GHG emission caps. The Nova Scotia 2007 Renewable Energy Standard Regulations specify the 2010 RES and 2013 RES.

The Nova Scotia RES requires that by year 2010[1], 5% of total Nova Scotia electricity requirements must be supplied by post-2001 renewable energy sources, rising to 10% by 2013. The term "post-2001" refers to electricity generators constructed on or after December 31, 2001, or a plant constructed before this date but having increased its output or undergone a major rebuild in lieu of retirement since then.

According to the Nova Scotia Wind Integration Study, 311 MW of installed wind in 2010 and 581 MW of installed wind by 2013 would exceed the RES, assuming that wind generation is the only alternative developed to achieve RES.

As indicated in the 2009 Nova Scotia Energy Strategy, the previous government was committed to setting new requirements for renewable electricity use for 2016 and 2020. The new government's provincial goal is at least 25 per cent renewable energy by 2015. The strategy also indicated that it may be possible to exceed this goal to as much as 40 per cent by 2020, through a combination of domestic wind, biomass, and tidal and imported renewable energy. However, prior to firm legal binding targets, all technical studies will be completed and options will be properly tested.

2.4 Generation Resources

2.4.1 Existing Generation Resources

The total installed generation resources in Nova Scotia is 2,320.9 MW. The majority of these generation resources are owned and operated by NSPI. The NSPI generation portfolio is primarily fossil-fuel based, the majority of which is low-cost coal and petroleum coke. The company also has bilateral contractual agreements with Independent Power Producers (IPPs), mostly wind, which amount to a total of 59 MW of non-firm contracts for energy. Table 2-4 summarizes the resource mix of NSPI's installed generation.

[1] In October 2009, a one year extension for 2010 limit has been granted in the Amendment to the Renewable Energy Standard Regulations.

Table 2-4 2006 Generating Resources (Source: IRP 2009 IRP Update Assumption)

Plant/System	**Fuel Type**	**Winter Net Capacity**	**Total**
Avon	Hydro	7.6	
Black River	Hydro	23	
Lequille System	Hydro	26	
Bear River System	Hydro	39.5	
Roseway	Hydro	1.6	
Tusket	Hydro	2.7	
Mersey System	Hydro	42	
St. Margaret's Bay	Hydro	10	
Sheet Harbour	Hydro	10	
Dickie Brook	Hydro	2.5	
Wreck Cove	Hydro	212	
Annapolis Tidal*	Hydro	3.7	
Fall River	Hydro	0.5	
Total Hydro			**381.1**
Tufts Cove	Heavy Fuel Oil/Natural Gas	321.0	
Trenton	Coal/Pet Coke/Heavy Fuel Oil	307.0	
Point Tupper	Coal/Pet Coke/Heavy Fuel Oil	152.0	
Lingan	Coal/Pet Coke/Heavy Fuel Oil	617.0	
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	171.0	
Total Steam			**1568.0**
Tufts Cove	Natural Gas	98.0	
Burnside	Light Fuel Oil	132.0	
Tusket	Light Fuel Oil	24.0	
Victoria Junction	Light Fuel Oil	66.0	
Total Combustion Turbine			**320.0**
Contracts(pre-2001)	Independent Power Producers	25.8	
Renewables(firm) (post 2001)	Independent Power Producers	25.7	
NSPI wind (firm)**	Wind	0.3	
Total IPPs & Renewables			**51.8**
Total Capacity			**2320.9**

*Capacity of Annapolis Tidal Unit is based on an average performance level at peak time. Nameplate capacity (achieved at low tide) is 19.4 MW.
** The assumed firm capacity value of wind is 32 percent for long-term planning purposes. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

2.4.2 Potential Generation Resources

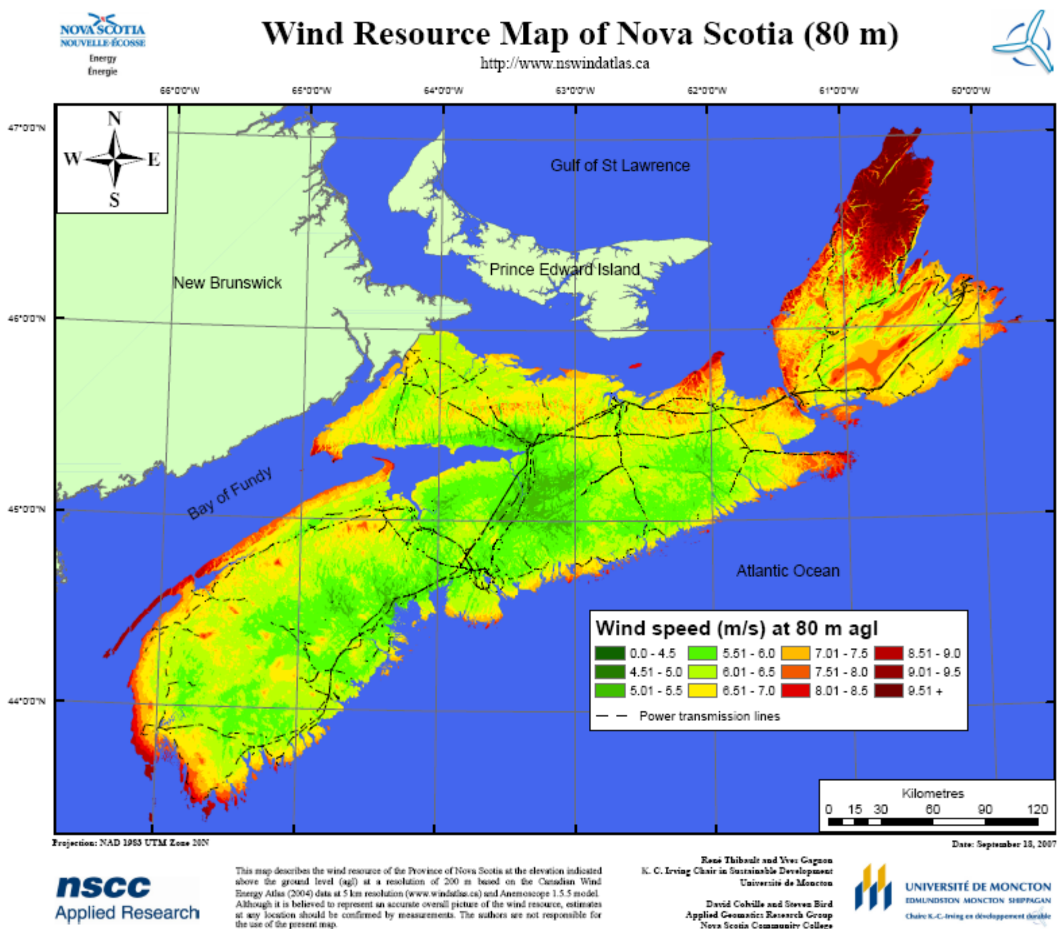
Additional generation resources and supply options which are available to Nova Scotia, and can be used to satisfy the RES and GHG emission caps, include the following: wind energy, biomass, tidal energy, wave energy, and compressed air energy storage (CAES) technology. The CAES could effectively be deployed for balancing supply variability as intermittent renewable energy (wind, tidal,…etc) levels increase in Nova Scotia. Imports from Lower Churchill and New Brunswick would provide alternative supply options, provided that the transmission system reinforcement within and outside Nova Scotia to achieve this will be in place. This section briefly discusses the potential of these renewable resources.

Wind Energy

Being an Island, Nova Scotia has rich with wind resources. Recently, the NS-DOE sponsored an initiative to develop the Nova Scotia Wind Atlas to help identify Nova Scotia's wind resources and stimulate its use. Figure 2-1 shows the wind resource map of Nova Scotia at a height of 80 metres. The colour on the map represents average annual wind speeds at a particular location, with the red colour indicating the region of the highest wind regime in Nova Scotia. As can be seen from this sample map, there are good wind regimes on the peripheral of Nova Scotia along the coast lines.

Nova Scotia has approximately 60 MW of installed wind capacity and a further 246 MW has been contracted to achieve the 2010 RES target. In addition, there are approximately 1,241 MW of wind generation projects in the NSPI Interconnection Queue. The Nova Scotia Wind Integration Study concluded that the 2010 and 2013 RES targets can be achieved using only wind resources. However, the study assumptions and modeling considered wind energy as a non-dispatchable but fully predictable resource. The assumption of full predictability of wind would tend to minimize the actual impact of wind variability on Nova Scotia electric system. The study results are indicative, but further study is required to consider wind variability and wind forecast error in more detail. The study emphasized that further studies need to be carried out to fully understand the impact of having these variable generation resources on the Nova Scotia power system.

Figure 2-1 Wind Resource Map of Nova Scotia (80 m)



Electricity systems around the world have adopted limits on the amount of installed wind power that can be connected to the system, ranging from 15% to as much as 35% of the total installed generation capacity in the control area (25% is fairly typical). A total of 35% of wind capacity can be justified if the system has other flexible resources, especially hydro, and sufficient interconnections with neighbouring systems. The Nova Scotia system has relatively inflexible base-loaded coal-fired power plants and limited interconnection capacity. Other provinces in Canada, and other jurisdictions across North America, have adopted greenhouse gas targets and intend to increase the amount of wind power connected to their systems. Merging control areas into a single larger control area will not necessarily increase the amount of wind power that can be accommodated overall. It is the diversity between wind patterns in different locations which would facilitate the integration of larger quantities of wind power over a wider area.

Integration of wind generation may be accommodated in the short term within the Nova Scotia system by relying on improved wind power forecast techniques. In the longer term, the system may not be able to accommodate larger penetration of wind generation without additional rapid response generation, or other resources required to balance variability of large wind. Since variations in wind velocity will be correlated less between distant points than they will between closer points, variability of electricity production tends to be reduced as the size of the system increases. The objective of increased wind penetration is therefore facilitated by integrating wind resources over a wider spatial geographic system.

Biomass

Biomass refers to energy resources derived from organic matter, including wood, wood waste, and agricultural waste. The existing biomass contribution is very small compared with other energy resources. NSPI has recently applied to Nova Scotia Utility and Review Board NSUARB to secure approval of a power purchase agreement PPA for 60 MW of Renewable Biomass Energy. The biomass plant would have a capacity factor of about 85%. This PPA would provide up to 400 GWH per year of energy which would assist significantly in meeting the 2010 RES requirements. The 60 MW biomass PPA hearing has been completed and the project was not approved. Currently, NSPI is also considering co-firing biomass at coal plants.

Tidal Energy

Nova Scotia Power Inc owns and operates the Annapolis Tidal Power Station, which is one of three tidal power plants in operation around the world. Annapolis has a capacity of 20 MW and a yearly output of 30 GWH. The output power of this facility can be predicted with good accuracy. Recently, the government of Nova Scotia invested $7-million in a research demonstration facility to test underwater turbines to convert tidal energy into electricity. At least, three companies plan to field test their technologies in the Bay of Fundy, which is the home of the highest tides in the world. According to some stakeholders' estimates, at best 300 MW can be developed in Bay of Fundy based on the success of a prototype scale installation. Given the expected long development cycle of the technology, it is likely this renewable resource will be commercially developed around the year 2020.

Energy Storage System

Energy storage systems are still to a large extent in their developmental stages. Theoretically, compressed air energy storage technology, coupled with gas turbines, can be utilized effectively as the wind power penetration levels increase in Nova Scotia. These systems can store the energy during off-peak hours and provide energy at peak hours at efficiency levels around 80%, with the equivalent of one third of the amount of natural gas that the gas turbine would consume to generate the same amount of energy. In addition, this technology can provide regulation service required to balance wind power. Another possibility for developing energy storage systems in Nova Scotia is to combine pumped storage with wind generation. The economics of developing these energy storage technologies in the Nova Scotia context are not known at this stage.

Natural Gas Generation

The future Nova Scotia electric system should be designed with sufficient flexible domestic resources to balance wind energy since there is no guarantee that NSPI could obtain such balancing from a neighbouring jurisdiction. The utilization of natural gas generation to displace part of coal generation would improve emission limits and provide a flexible resource within Nova Scotia to balance the variability of wind energy.

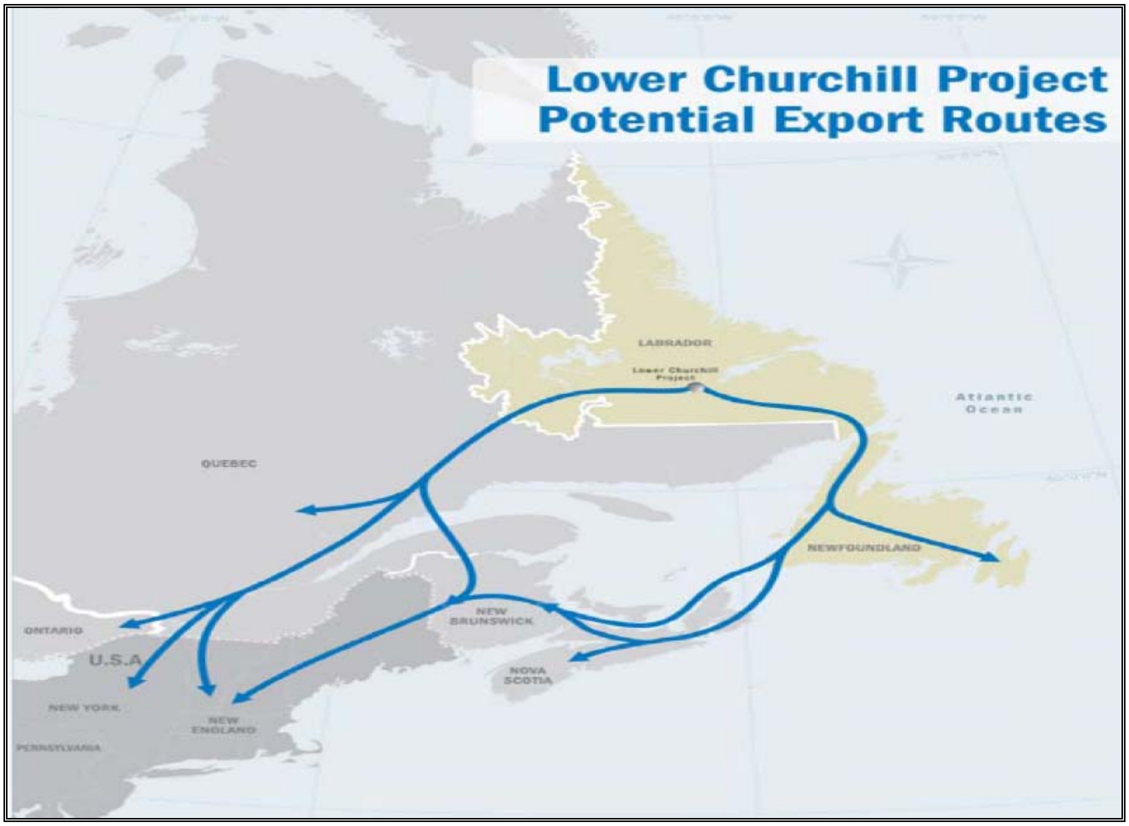
Import from Lower Churchill

The Lower Churchill River Project has a hydro-electric potential of up to 2,800 MW: 2,000 MW and approximately 12 TWh from Gull Island, and 800 MW and 5 TWh from Muskrat Falls. This project could provide a significant clean and renewable energy supply.

Studies are currently underway to investigate transmission requirements and technical and economic feasibilities to access multiple markets including Québec, Ontario, and New England via several different transmission routes: through Newfoundland and the Maritimes provinces (Nova Scotia and/or New Brunswick), or through Québec, or following multiple routes. (See Figure 2-2)

In this regard, Emera/NSPI signed a MOU with Nalcor Energy on January 2008 to study the technical, economic, financial and regulatory aspects related to exporting power from the Lower Churchill project.

Figure 2-2 Lower Churchill Project Potential Export Routes



Import from Point Lepreau II Nuclear Energy

In a bid to meet renewable energy targets and limit GHG emissions, the New Brunswick government is sponsoring development of one or two new nuclear energy reactors at Point Lepreau. If one of these reactors is developed, there will be an opportunity for Nova Scotia to import clean energy from Point Lepreau nuclear generation.

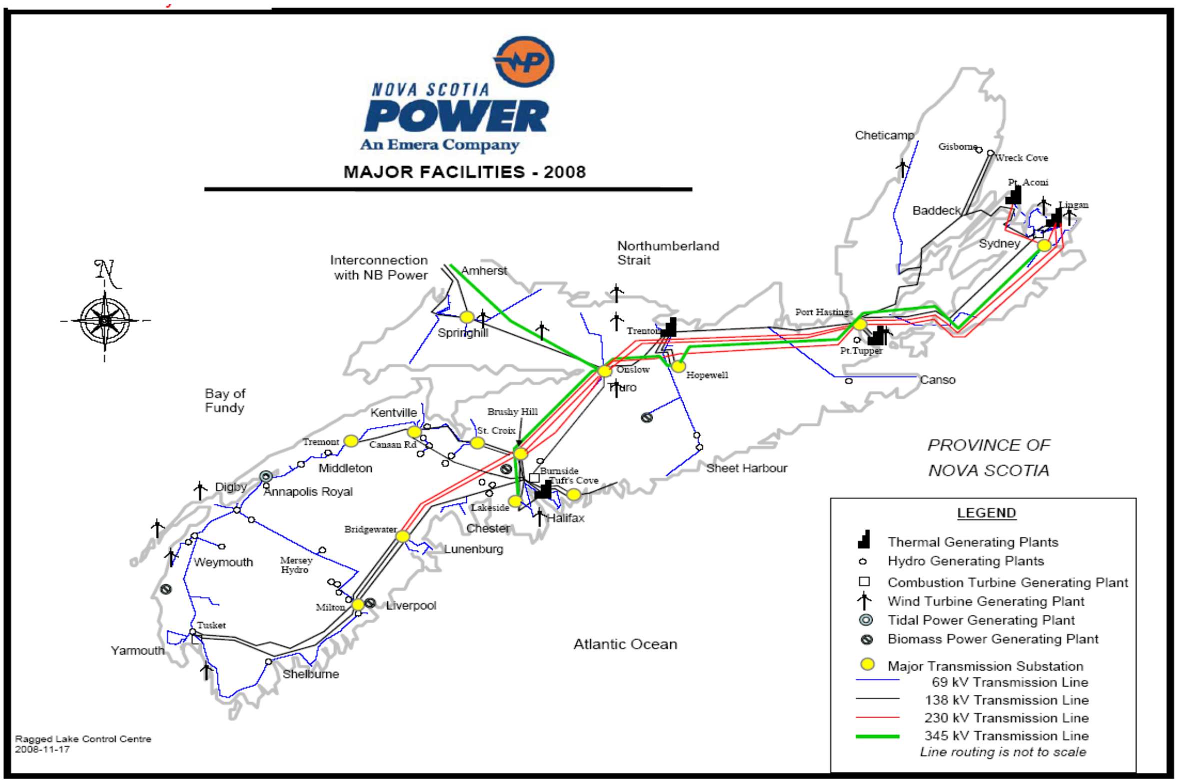
2.5 Transmission System

2.5.1 Existing Transmission System

NSPI owns and manages 5,200 km of bulk transmission system and about 25,000 km of distribution lines distributed across the province of Nova Scotia. The existing transmission voltages in Nova Scotia are 69 kV, 138 kV, 230 kV, and 345 kV. The 345 kV and 230 kV transmission lines constitute the backbone of the provincial transmission system. The 345 kV network consists of a single 266 km line from Woodbine in the Sydney area to Onslow in the Truro area. This single line extends a further 106 km from Onslow to Lakeside in the Halifax area. The 230 kV network consists of two 240 km transmission lines which run from Lingan in the Sydney area to Port Hastings in the Port Hawkesbury area; and three circuits from Port

Hastings to Brushy Hill in the Halifax area via Onslow. In addition, the 230 kV network has two circuits which connect Brushy Hill in the Halifax area to Bridgewater in the South Shore area. The bulk transmission system configuration is shown in Figure 2-3.

Figure 2-3 Bulk Transmission System Configuration



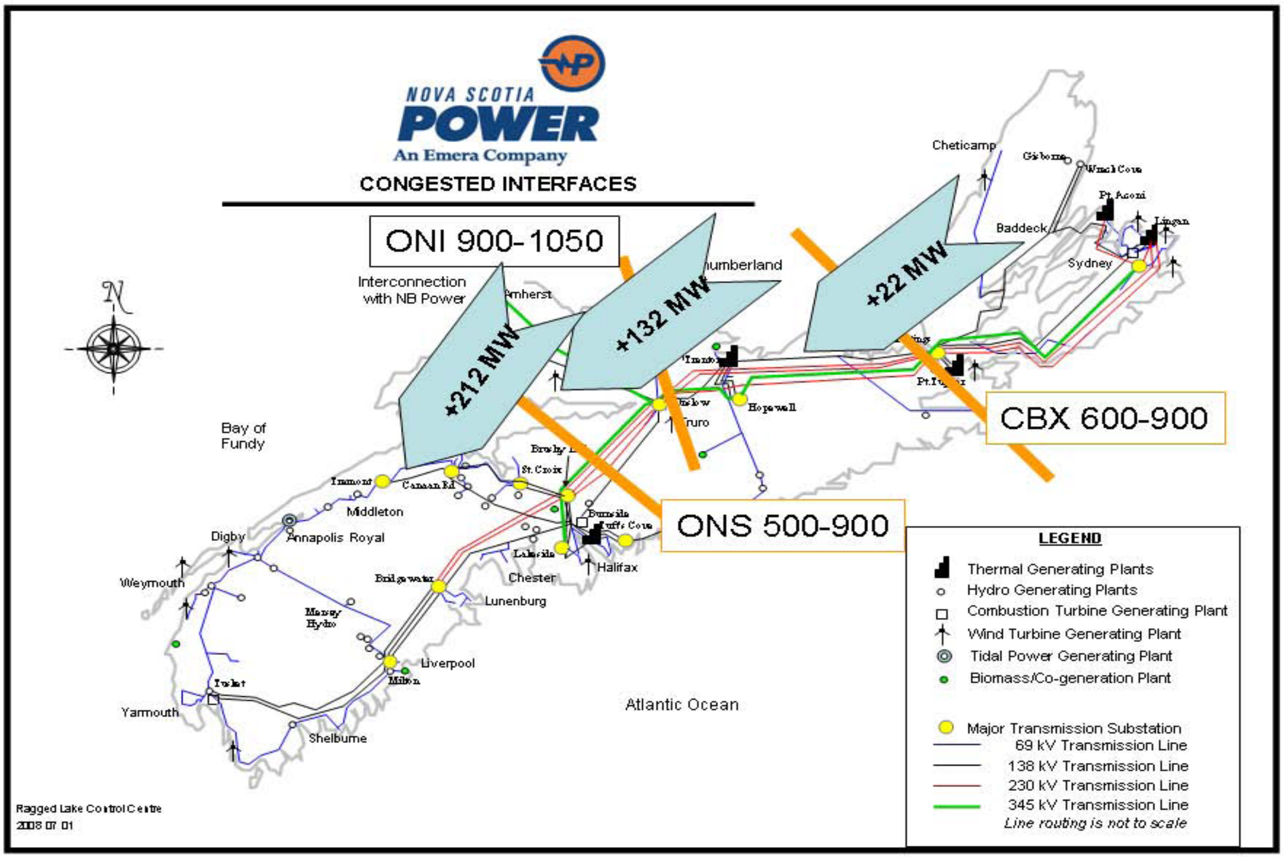
2.5.2 Major Transfer Limits and Special Protection Schemes

The Nova Scotia transmission system has three major interfaces: the Cape Breton (CB) Export interface, the Onslow Import transfer interface, and the Onslow South transfer interface. The existing power transfer limits on these interfaces have been determined by NSPI through dynamic stability studies. If any of these interface flows approach the set limits, a Special Protection Scheme (SPS) is invoked after selected system contingencies to maintain system stability and to ensure that no thermal loading and voltage limits are violated. Depending on system conditions, these transfers have to meet the following ranges:

- Cape Breton (CB) Export Transfer Interfaces (600 MW - 900 MW)
- Onslow Import Transfer Interfaces (900 MW - 1050 MW)
- Onslow South Transfer Interfaces.(500 MW -900 MW)

Nova Scotia transmission interface constraints are shown in Figure 2-4. The arrows shown in this figure represent the incremental power flow across the interfaces associated with renewable generation projects awarded in the last RFP.

Figure 2-4 Nova Scotia Transmission Interface Constraints



2.5.3 Transmission System Operation

The Nova Scotia Power System Operator (NSPSO) functions as part of the NSPI Customer Operations Division. NSPSO fulfills its obligations, following the standards of conduct approved by UARB, to ensure that market sensitive information is not intentionally or inadvertently shared among other groups of NSPI, particularly the transmission and the wholesale merchant groups. The roles and responsibilities of NSPSO are defined in the Market Rules, and include: the reliable and safe operation of the bulk electrical system; operation of the wholesale market; administration of the market rules; reliability and system planning; and administration of the Open Access Transmission Tariff (OATT) and the Generator Interconnection Procedures (GIP). The roles of NSPSO are described in more detail in Section 6.1.2.

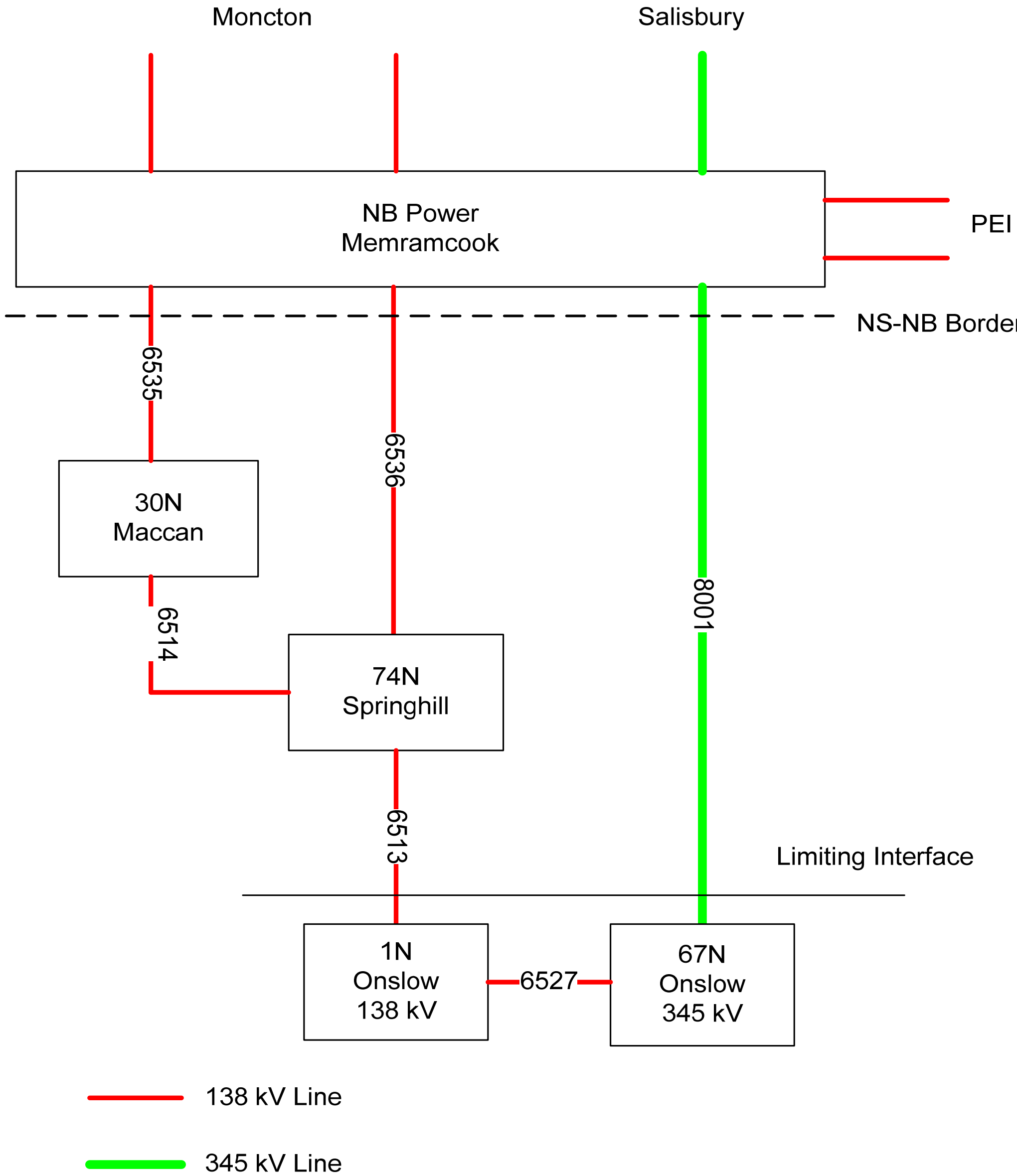
2.5.4 Interconnection with Neighbouring Systems

Nova Scotia is interconnected with the New Brunswick electric system through one 345 kV tie and two 138 kV tie lines. . A simplified Singe Line Diagram (SLD) for the NS-NB intertie is presented in Figure 2-5.

The intertie with New Brunswick has a posted export capability of 350 MW with 175 MW of firm capacity and 175 MW of non-firm capacity, and import capability of 22 % of native Nova Scotia load, which represents up to 300 MW. The import transfer capability for the loss of the 345 kV tie is about 100 MW, corresponding to the limits on the remaining 138 kV ties. Imports above this level will result in Nova Scotia islanding from the rest of the interconnection upon loss of the 345 kV tie line, and controlled load shedding to varying degrees depending on load and generation conditions.

The Moncton area in the New Brunswick system has witnessed high load growth in recent years. This load growth adds further constraints on the NS-NB intertie (especially Nova Scotia import capability) during peak winter demand. A study regarding revision of the posted intertie capability between Nova Scotia and New Brunswick, which reflects recent operational constraints, is presently underway.

Figure 2-5 NS-NB Intertie Arrangement



2.5.5 East-West Trans Canada Transmission

Several potential ‘East-West’ transmission projects, if they went ahead, would go some way toward strengthening the east-west interconnections and increasing north-south flows associated with international trade in electricity. Such a representation conjures up the concept of an east-west grid across parts of Canada while much of the transmission is currently North to South. Federal Government support would increase the likelihood of such projects. In the present context, transmission from Labrador to Québec, Maritimes and Ontario would tend to increase the resources available to the Maritimes.

3. Overview of Regional Electric System

3.1 Introduction

The Eastern Canadian provinces and the New England states are all expected to exhibit significant increases in the use of renewable energy, arising from legislated greenhouse gas targets and/or renewable portfolio standards. Table 3-1 presents the existing renewable energy resources and future renewable targets established in the Eastern Canadian provinces and the New England states. The amount of generation capacity from wind in the Eastern Canadian provinces will grow from 627 MW to more than 5,000 MW of wind in 7 years. In the NBSO control area (which includes Nova Scotia), it is possible that generation capacity from wind will reach 1,100 MW by 2013. This amount would represent 19% of the peak load, and 46% of the lowest system demand. The Lower Churchill projects, upon completion, will add about 2,800 MW of clean renewable energy, which will need transmission infrastructure and interties for connection to possible markets in both Canada and the USA.

This section discusses the existing and planned transmission facilities and interties in the eastern Canadian provinces and New England which would play a major role in integration of renewable resources and facilitate power trade between these provinces. The regional market structure and the operational and commercial aspects of the market are discussed in detail in Section 6.

Table 3-1 Eastern Canadian & New England Renewable Energy Targets

Canada- Eastern Provinces	**Existing**	**Future Renewable Target**
Québec	422 MW	~6% by 2015 (4,000 MW) – wind only
New Brunswick	96 MW	10% by 2016 (~550 MW) – all RE
Nova Scotia	61 MW	10% Incremental post 2001 (~580 MW) – all RE (25% by 2015)
Prince Edward Island	72 MW	15% by 2010 (60 MW) – wind only
USA- New England States	**Existing**	**Future Renewable Target**
Connecticut	0 MW	23% by 2020
Maine	42 MW	10% by 2017
Massachusetts	5 MW	4% by 2009
New Hampshire	1 MW	16% by 2025
Rhode Island	1 MW	15% by 2020
Vermont	6 MW	10% by 2013

3.2 New Brunswick & New England Transmission

New Brunswick is interconnected to neighbouring power systems in Québec, New England, Nova Scotia, Prince Edward Island, Northern Maine, and Eastern Maine. The Québec interface is made up of two HVDC stations: Madawaska HVDC on the Québec side, and the Eel River HVDC on the New Brunswick side. Figure 3-1, Figure 3-2 and Table 3-2 present the interconnection transfer capability between New Brunswick and neighbouring systems. The Nova Scotia interface was discussed previously in Section 2. The Québec NB transfer capability is comprised of 750 MW HVDC service and 350 MW of NB load that can be radially synchronized to NB. It should be noted that NERC requires firm transfer capability to be calculated with one element out of service, transfer levels listed in Table 3-2 are conditional on all elements being in service.

From a system reliability standpoint, the New England interface is the most critical interface for the Maritimes Area. It is the only synchronous connection between the Maritimes Area and the

Eastern Interconnection. Since the New England interface is not thermally limited but stability limited, the summer and winter Total Transfer Capability (TTC) import and export limits for the summer and winter cases are identical.

Until recently, the New Brunswick and New England systems were connected by single 345 kV intertie. The whole Maritimes area was at risk of islanding in the event of a loss of this single intertie. In December 2007, a second 345 kV intertie was commissioned between New Brunswick and New England, connecting Point Lepreau in New Brunswick to Orrington, Maine. As a result of this project, the maximum transfer capability from New Brunswick to New England increased from 700 MW to 1000 MW, and the firm transfer capability from New England to New Brunswick increased from 100 MW to 400 MW. This second intertie also significantly improves the reliability of the Maritimes system, since loss of either of the two interconnections to New England will no longer result in the separation of the Maritimes from the interconnected New England power system.

The Orrington-Maine South flow, the total southward flows leaving the Bangor area, is limited to 1,200 MW. Currently, this interface is composed of a single series-compensated 345 kV line, and loss of that line results in a forced separation of Maritimes/Bangor Hydro systems. The limited intertie capacity between New Brunswick and Maine, and further limiting constraints in the transmission paths from Maine down to southern New England, put a physical constraint on the amount of energy that the Maritimes can export to New England. In addition, the intertie capacity between Nova Scotia and New Brunswick adds further constraints for exporting energy from Nova Scotia.

Table 3-2 New Brunswick Interconnection Transfer Capability

Neighbouring System	Transfer Capability to New Brunswick (MW)	Transfer Capability from New Brunswick (MW)
Québec	1,100	770
New England	550†	1,000††
Nova Scotia	350†††	300†††
Prince Edward Island	124	222
Northern Maine	90	100
Eastern Maine	15	15

† Transfer capability from New England varies according to Maritimes Area largest contingency, load levels in Maine, status of area 345 kV MVAR resources, and the generating status of large generators near Bangor, Maine.
†† Transfer Capability to New England has a long term reservations, refer to Section 6 for more details
††† Transfer capability to and from Nova Scotia is constrained by the import and export limits of the Nova Scotia electricity system.

Figure 3-1 New Brunswick Intertie Import Capabilities

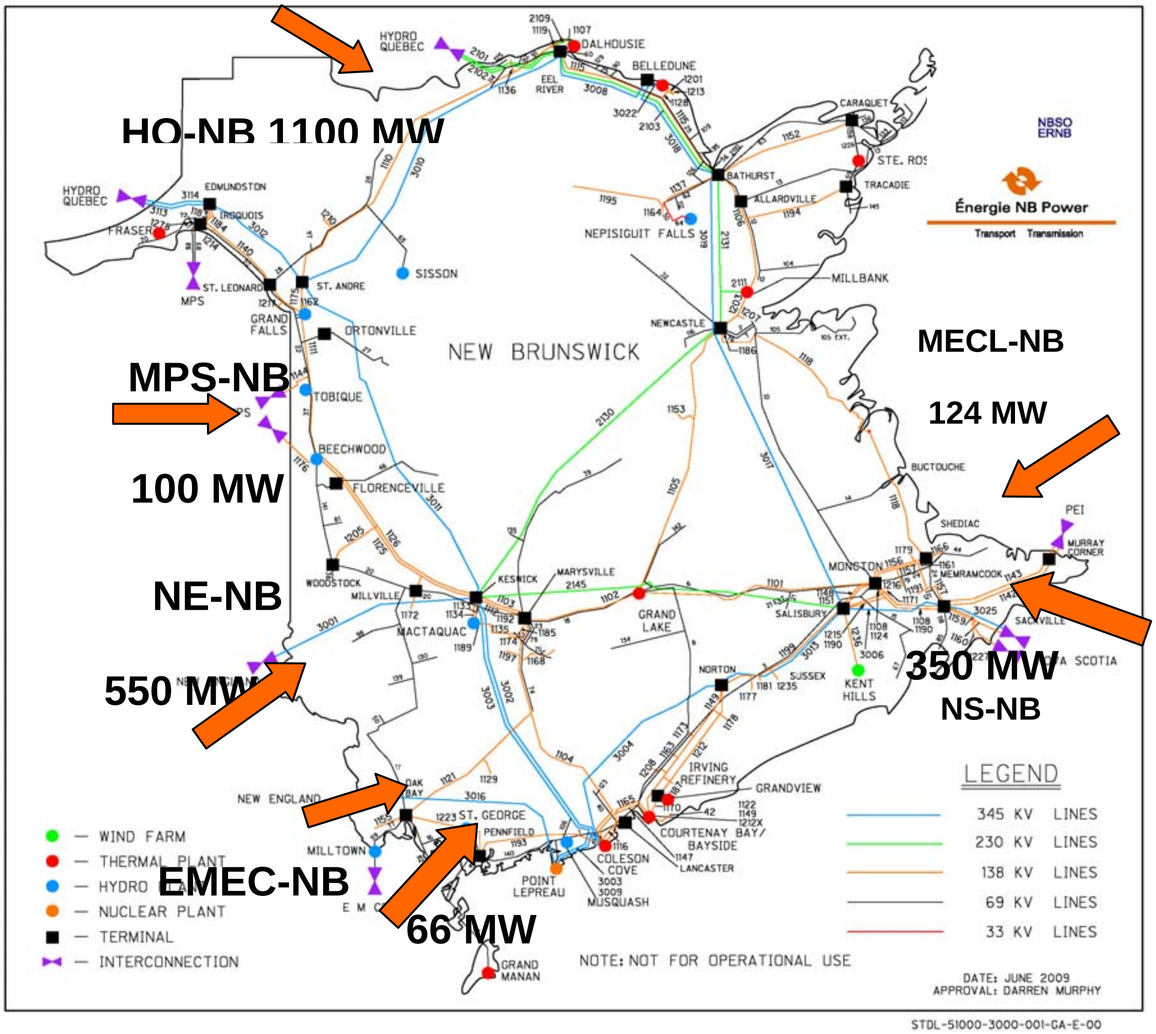
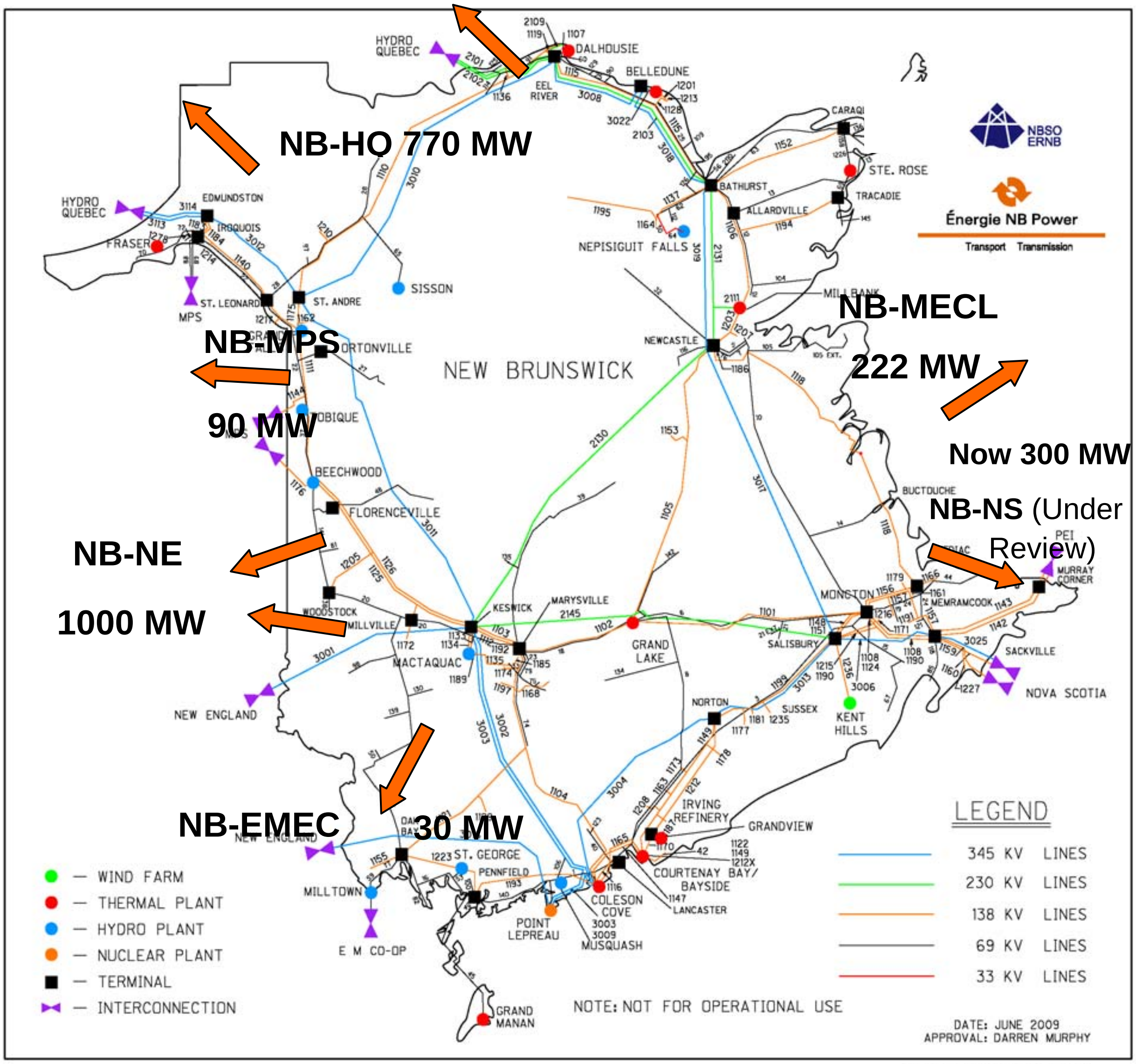


Figure 3-2 New Brunswick Intertie Export Capabilities



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3.3 Québec

Hydro-Québec TransÉnergie is the main transmission company in Québec; it has 15 interconnections with systems in neighbouring provinces and states, providing a total export capacity of more than 6,700 MW and import capacity of more than 9,700 MW. These facilities allow interchanges with Newfoundland and Labrador, New Brunswick, Ontario and the U.S. Northeast. Hydro-Québec TransÉnergie does not have a direct intertie with the Nova Scotia transmission system, but it is connected to it via the New Brunswick grid. Table 3-3 presents the interties transfer capacities.

Table 3-3 HQ TransEnergie Intertie Transfer Capacities

Neighboring system	Import mode (MW)	Export mode (MW)
Churchill	5,150	0
New Brunswick	770	1,100
Ontario†	720	1,295
New England	1,970	2,275
New York	1,100	2,125

† Not including the new 1250 MW Intertie just added with Ontario

3.4 Newfoundland and Labrador

The Newfoundland and Labrador electricity system can be considered as two separate electric systems. The Newfoundland system has no interconnection with other systems. The Labrador interconnected system serves principal communities in Labrador, and is interconnected with Hydro Québec through the high voltage transmission lines from Churchill Falls. Newfoundland & Labrador Hydro (NLH), a provincial crown corporation, owns and operates the Labrador system, along with most of the island transmission and 80% of the island generation. Nalcor Energy is in the process of developing the Lower Churchill project. The project consists of hydroelectric generating facilities at Gull Island and Muskrat Falls, and interconnecting transmission lines to the existing Labrador grid. The Gull Island facility will consist of a generating station with a capacity of approximately 2,000 MW. The Muskrat Falls facility will consist of a generating station approximately 800 MW in capacity. As discussed in Section 2, Nalcor Energy is exploring the possibility of evacuating most of the energy generated from the Lower Churchill project via various alternative routes.

3.5 Prince Edward Island

The power system in Prince Edward Island is mostly owned and controlled by Maritime Electric, and is strongly linked to New Brunswick. In many respects, Prince Edward Island operates as a load connected to the New Brunswick system. Historically, Prince Edward Island has not operated sufficient generation to supply its native load. Wind generation on Prince Edward

Island is changing that balance. Prince Edward Island is radially connected to New Brunswick through two submarine cables each having a continuous rating of 111 MVA.

3.6 Possible Future Interconnections

3.6.1 Second NS-NB Intertie

A second NS-NB intertie would help the Nova Scotia system from many different perspectives. The advantages of having second NS-NB intertie can be summarized as follows:

- Improved Nova Scotia system reliability and reduced risk of Nova Scotia system islanding
- Additional balancing service for local wind generation in both provinces, due to wider geographic dispersion. This would allow for accommodating more wind generation.
- Export of excess renewable energy
- Facilitate import of power from Point Lepreau
- Facilitate interconnection of Lower Churchill to Nova Scotia.

The analysis presented in this study will attempt to identify the suitable timing and triggering events for the second intertie between NS-NB.

3.6.2 Newfoundland and Labrador Intertie

Nalcor Energy is simultaneously pursuing several transmission corridors and customers. One of the planning concepts under investigation is to develop an overhead/submarine HVDC link at +/- 450 kV from Gull in Labrador to Soldiers Pond in Newfoundland, carrying on to a third terminal somewhere in the Canadian Maritimes, with a possible termination point at one of Sydney, Onslow, or Salisbury. The total estimated length of required transmission is 1,200 km. Realization of this option would also be coupled with the need for some portion of the Lower Churchill power to be exported through Nova Scotia to export markets in New England or, via transmission links to/through New Brunswick, or directly from Nova Scotia to New England.

3.6.3 New Brunswick-New England Intertie

New Brunswick and Maine are exploring the development of a northeast energy corridor. Two different concepts have been considered by different development groups.

On March 25, 2009 Irving Oil announced that it is conducting commercial and technical feasibility studies on the first phase of development of the corridor, which includes 1,200 to 1,500 MW of electrical transmission capability, wind generation, and a base load natural-gas-fired co-generation plant to release the wind-generation capacity. This corridor is expected to cost several billion dollars.

In a separate initiative, the Team CANDU consortium has conducted a feasibility study for development of one or two Advanced CANDU Reactors at the site of the existing Point Lepreau Nuclear Generating Station. This feasibility study was undertaken with support and encouragement from the Government of New Brunswick, as part of the “Energy Hub” concept promoted by the province. Although the feasibility studies are not complete, it is understood that the planning concepts included consideration of transmission options to deliver some portion of the generated power from Pt. Lepreau to Southern New England. Again, a new transmission corridor from Pt. Lepreau to Southern New England would be expected to cost over $2 Billion.

Either of these interties, upon realization, would reduce the physical transmission constraints between New Brunswick and New England and allow for more energy trade between the Maritimes and New England.

3.6.4 NS-NE Intertie

A similar energy corridor concept is possible between Nova Scotia and New England by utilization of an HVDC submarine cable running between Nova Scotia and New England. This initiative would require a multi-billion dollar investment, and would need a high level of cooperation between the Nova Scotia government and stakeholders, New England stakeholders, and private developers to develop wind, tidal, and other generation facilities required to offset the high costs associated with this project. The authors are aware of two attempts to develop such a concept in the past, including project concepts by the GenPower Project and the Neptune concept.

4. Transmission System Enhancement and Strengthening

4.1 Introduction

This section reviews recent NSPI work on transmission enhancement and strengthening required to meet load growth, Renewable Energy Standards (RES) and reliability targets. The analysis in this section covers the period up to 2012, including forecast load, demand side management, and committed generation development up to that date.

4.2 Planning Criteria and Assumptions

4.2.1 Transmission System Classification

The interconnected system of Nova Scotia is divided into several levels, each of which is governed by different planning criteria. The Interconnected Transmission System refers to the combination of primary, secondary, and electrically remote transmission.

The Primary Transmission System is defined as: the 345 kV transmission system interconnecting Lakeside-Onslow-Hopewell-Woodbine, and Salisbury, New Brunswick; the 230 kV transmission system interconnecting Brushy Hill-Onslow-Lingan and Pt. Aconi; and the interconnecting 345/230 kV transformation between them.

The Secondary Transmission System is defined to be that part of the system which serves mainly to interconnect miscellaneous generation and Primary Transmission with sub-transmission at major load centres. This definition then governs most of the 138 kV and 69 kV systems, plus certain 230 kV lines that are not included in the Primary Transmission system.

Electrically Remote Transmission is defined by those buses at which ultimate fault levels are projected to be less than 1,500 MVA.

4.2.2 System Planning Criteria

The NSPI Primary Transmission System is planned, designed and operated in accordance with single contingency criteria. NSPI is a member of the Northeast Power Coordinating Council (NPCC). Those portions of NSPI's Primary Transmission System wherein single contingencies can potentially adversely affect the interconnected NPCC system are designed and operated in accordance with the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems.

NSPI makes use of Special Protection Systems (SPS) within SCADA to maximize the utilization of transmission assets. These systems act to maintain system stability and remove equipment overloads post contingency, by rejecting generation and/or shedding load. The NSPI system has several transmission corridors that are regularly operated at limits. NSPI makes use of SPS to permit these transfer limits on these corridors.

4.2.3 Discussion on Nova Scotia System Reliability

The system was designed and built to meet the transmission planning criteria before NSPI joined NPCC in 1985. Currently, the NSPI planning criteria are under review at NSPI. NERC/NPCC standards do sanction load shedding for a first contingency outage.

Liberty Consulting Group examined the NSPI system reliability for the UARB. The Liberty consultant report concluded that there will be a risk of load shedding for up to 55,000 customers if Under Frequency Load Shedding (UFLS)-Stage 1 is activated following the trip of the 345 kV intertie between Nova Scotia and New Brunswick while the import level exceeds 10% of system demand. If the import level exceeds 25%, the number of customers which would be prone to risk of load shedding, upon the activation of the second stage of the UFLS, would increase to 125,000 customers.

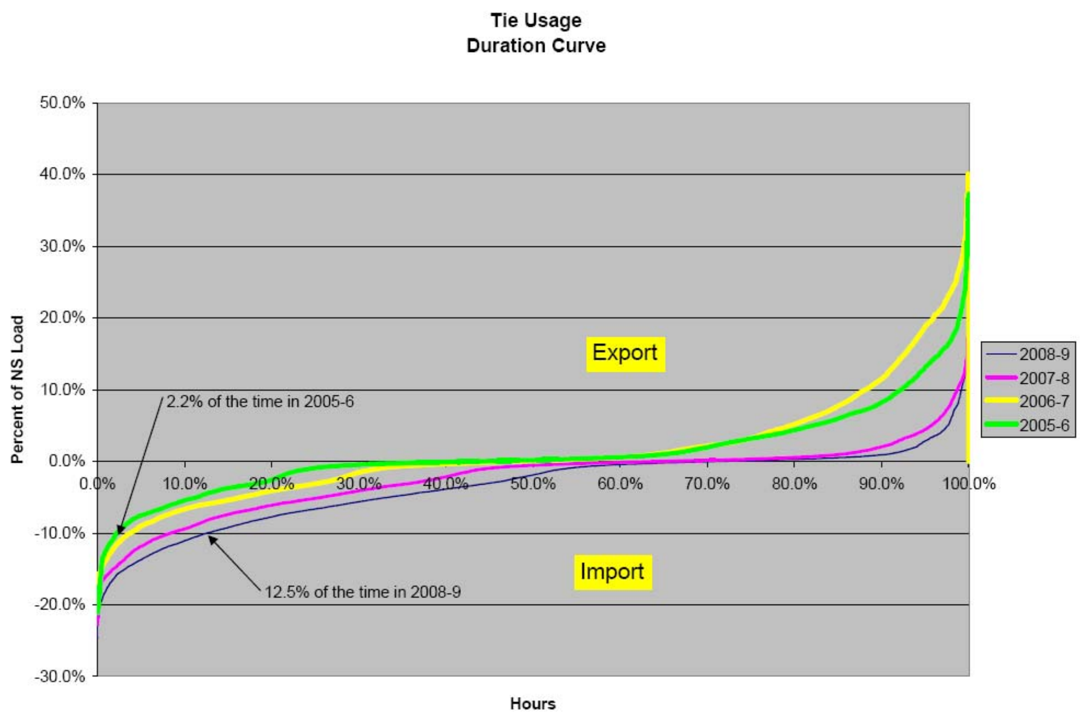
NSPI has traditionally acknowledged this risk, but argued that the probability is very low since the import levels traditionally exceeded 10% of system demand for less than 3% of the year. Furthermore, the frequency of intertie trips has historically been once every year and a half, so the risk of load shedding was previously deemed to be acceptable.

There is a change in the pattern in the use of the intertie as Nova Scotia currently imports more than 10% up to 12.5% of the time to reduce their energy costs (see Figure 4-1). It is evident that the customers of NSPI are exposed to a higher risk of automatic load shedding to control Nova Scotia system frequency. In addition, the loss of the NS-NB intertie will cause an islanding situation for Nova Scotia. With increased wind generation penetration levels on the system, there will be more reliance on tie-line imports (wind forecast errors) and greater difficulty in controlling the frequency, even if the import level was below 10% before islanding, which means a higher probability of load shedding.

Power imported to Nova Scotia flows through the Moncton/Salisbury area of New Brunswick. As there is no generation in the Moncton/Salisbury area, and only a limited amount of generation in Prince Edward Island, power flowing into Nova Scotia is added and shares transmission capacity with the entire load of Moncton, Memramcook, and PEI. The New Brunswick System Operator restricts export to Nova Scotia to a level such that any single contingency does not cause adverse impacts on NB or PEI load. That means in addition to the loss of the 345 kV line between Onslow, NS and Memramcook, a critical transmission element loss in Moncton/Salisbury area can, under certain operating conditions, result in Nova Scotia becoming separated from the New Brunswick Power system while importing power.

From a reliability point of view, the addition of any second intertie will enhance NSPI system reliability by greatly reducing the probability of activation of the UFLS scheme. This is provided that the limiting constraints on the New Brunswick side at Moncton/Salisbury area have been addressed in concurrent manner.

Figure 4-1 Tie Usage Duration Curve



4.3 Planned Transmission System

4.3.1 Transmission Systems Programs

NSPI has a number of programs aimed at the reliability and renewal of the transmission system. The first program is aimed at improving the reliability of the transmission system and is centered on detailed transmission facility inspections and associated prioritization of equipment replacement. The second program is a pole treatment and replacement program that aims to include approximately 4,800 poles per year. In addition, a transmission line upgrade program to increase line thermal ratings has been initiated by NSPI to maximize the utilization of the existing assets.

Details of required transmission system reinforcement and life extension investments are presented in the NSPI 10 Year System Outlook, June 2009. Possible transmission options for RES developments and other committed resource integration beyond 2012 are outlined in Section 5.

Primary Transmission System Plan:

The existing and committed Wind Farms utilize the existing transmission facilities and therefore there is no need to add any additional primary transmission system elements.

Secondary Transmission System Plan:

These projects are part of the 2009 NSPI Outlook Plan:

- A 345 kV circuit between Onslow and Lakeside is being uprated by increasing the operating temperature of the line.
- Thermal uprating of a 138 kV circuit between Port Hastings and Glen Tosh
- The construction of a 138 kV circuit between Canaan Road and Tremont

Other Transmission System Categories:

Electrically remote transmission, sub-transmission and interconnections to accommodate wind and transformer substations will be built as needed to meet expected load growth and wind integration in Nova Scotia.

Transmission Facilities to Improve Major Transmission Limits

- Energy generation from wind power projects typically increase on windy days when ambient temperatures are low. The static thermal ratings of power transmission lines are based on worst case conditions with typically higher temperatures and light wind. The implementation of dynamic thermal ratings on primary and secondary transmission systems would provide additional room to accommodate this generation, since it will usually provide dynamic ratings which exceed the static thermal ratings. It is recommended that NSPI explore implementation of dynamic thermal ratings in the near future. This is an operational measure which could be used on existing facilities and can be employed until necessary transmission system reinforcement is in place.

- The Onslow-South interface limit can be increased with the addition of 100 MVAR of reactive power support at Onslow 230 kV bus, but the benefit of the increase will be limited by the summer thermal rating of L6001. Overload of L6001 could be managed by starting the 10-minute reserve units at Burnside post-contingency and by using the dynamic thermal rating for L6001.

4.4 Conclusions & Recommendations

4.4.1 Conclusions

- Minor transmission reinforcements for the strengthening of the Nova Scotia system in the near future have been obtained and are listed in this section.

- The Nova Scotia system can be operated reliably within the security limits of the existing transmission interfaces with the addition of the new wind generation facilities. This may require a change in the economic dispatch principles presently in use.

- The system can be reasonably re-dispatched following the loss of the most critical elements on the Nova Scotia system while observing the continuity of supply.

- This may not be the case following loss of the single 345 kV tie between Nova Scotia and New Brunswick, which could put Nova Scotia in islanded mode of operation. With increased reliance on imported power and increased penetration of wind generation, a plan to have another intertie with New Brunswick would be very desirable to assure reliability and continuity of the supply.

- From a reliability point of view, the addition of a second 345 kV inter-tie would virtually eliminate the need for Under Frequency Load Shedding (UFLS) and greatly enhance NSPI system reliability.

- Studies are required with New Brunswick regarding transmission upgrade in the Moncton/Salisbury area to support area loads and the reliable operation of a potential second 345 kV intertie between New Brunswick and Nova Scotia.

4.4.2 Recommendations

- Adopt dynamic thermal ratings (using physical monitoring equipment where required for specific limited transmission lines) which could release more transfer capacity to evacuate wind power on the existing transmission infrastructure. A study should be undertaken to quantify the benefit of the use of this technology in Nova Scotia. This should be thought of as an operational measure until system reinforcement is in place.

- Monitor the achievement of the DSM targets and investigate the possible need for reactive power requirements at Onslow to maintain system reliability.

- Forecast future NS-NB intertie usage and the need to add a new tie line with committed wind projects.

- Carry out joint planning studies (with NB and or Regional) for the transmission system reinforcement requirements in NB in the Moncton/Salisbury area for the development of a second 345 kV intertie.

5. Increased Role for Renewable Resources

5.1 Introduction

This section discusses transmission options to meet an increased role of renewable energy supplies under a variety of assumed resource development scenarios. These resource development scenarios and transmission options were derived from various information sources including, but not limited to, discussion with study stakeholders, Nova Scotia Wind Integration Study, 2009 Nova Scotia Transmission Outlook and the Nova Scotia 2009 Integrated Resource Plan basic assumptions. The vision presented in this section presents a high level "snapshot" of possible generation scenarios which could unfold and associated transmission options. This section focuses on transmission options listed below individually, as well as the collective impacts of various possible combinations of these options.

The options considered in this study include:

1. Addition of Wind Energy:
    a. Addition of about 300 MW of Wind Power by 2010 in Nova Scotia
    b. Addition of about 500 MW of Wind Power by 2013 in Nova Scotia
    c. Addition of about 800 MW of Wind Power by 2020 in Nova Scotia
    d. Addition of more than 1000 MW of Wind Power beyond 2020 in Nova Scotia
2. Development of 60 MW of biomass by 2010 in Eastern Nova Scotia
3. Development of 250-350 MW of large gas generation as needed
4. Development of about 600 MW of Tidal Power beyond 2016 at Bay of Fundy
5. Import 300 MW of Hydro Energy from Lower Churchill beyond 2020
6. Import 300 MW of Nuclear Power from the proposed Point Lepreau II nuclear project beyond 2020
7. Development of 175 MW of Compressed Air Energy Storage (CAES)

Two timeframes are considered in this study: the medium term timeframe, which discusses the prospects of transmission system development five years out; and the long term timeframe, which presents the prospects of transmission system development in the longer term to 2020 and beyond. Analysis of two snapshots, namely 2013 and 2020, are used to illustrate the medium and long term timeframe transmission options.

This section provides a high level “snapshot” of the potential transmission option and is not a transmission system plan. Transmission plans will depend on the pace of evolution of generation resources, load growth rates, demand side management initiatives, as well as development in neighbouring jurisdictions.

The vision presented for the long-term transmission options was based to a large extent on the input received from the study stakeholders. The scenarios presented for the long-term transmission vision try to capture the common transmission elements which would be needed with all scenarios. The assumptions in the Nova Scotia Wind Integration Study and governmental policy tend to encourage the development of Nova Scotia renewable resources up to the RES and GHG emission caps. Some stakeholders would like the export options to be considered, namely the export of large amounts of renewable energy to the USA, while others would like the import option to be included, namely import of power from Lower Churchill and/or the proposed Point Lepreau II nuclear project.

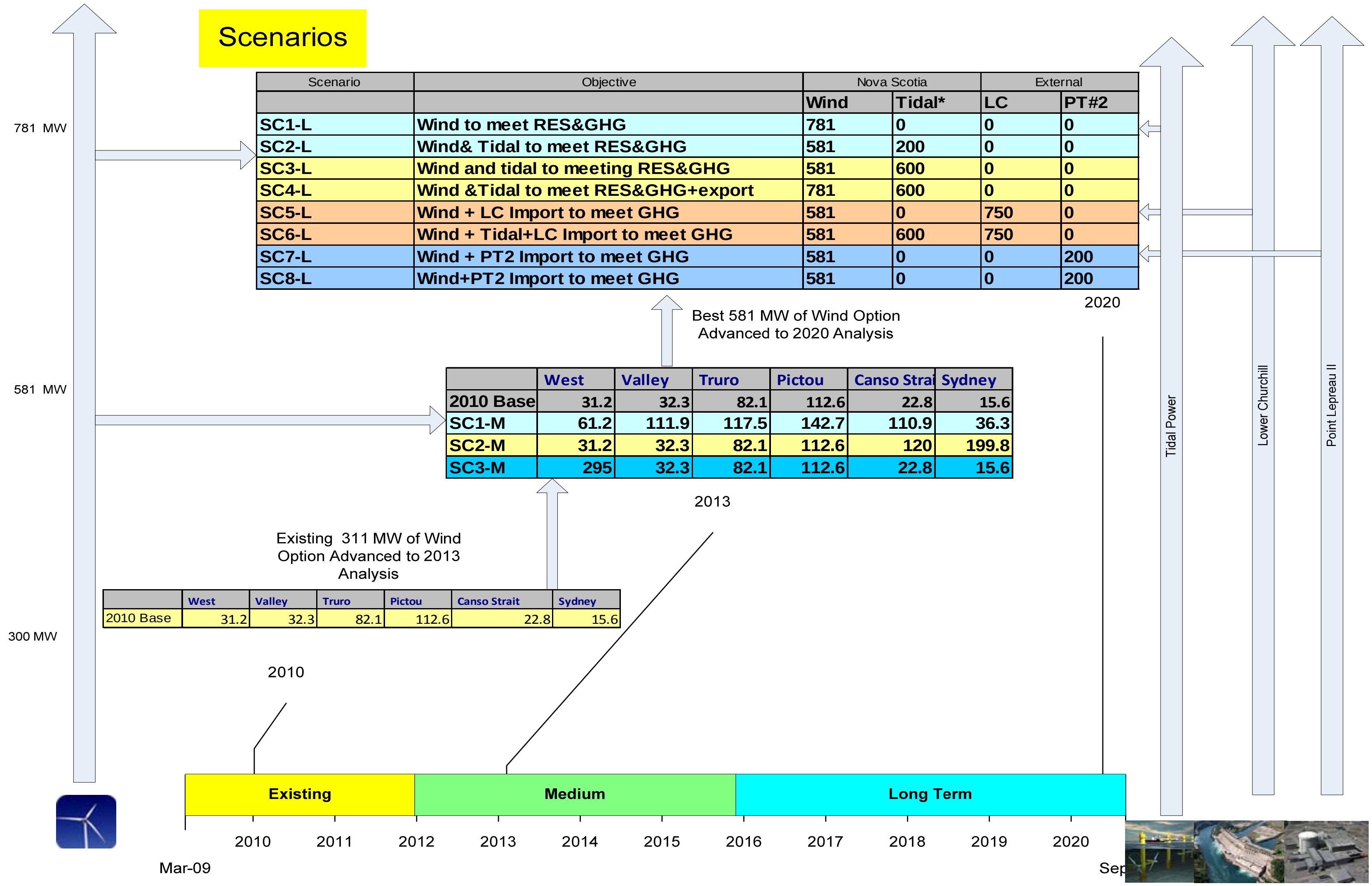
The earliest in-service date for potential development of Point Lepreau II nuclear unit in New Brunswick and the Lower Churchill Hydro project will be after 2016. The commercial development of tidal energy will likely take a longer period to develop. Over the medium term period to 2013, wind and biomass generation are the only feasible options to meet the 2013 RES and 2015 GHG emission caps using Nova Scotia sources. Gas turbines in the Halifax area, or in eastern NS, could be added as needed to achieve 2015 GHG emission caps.

Figure 5-1 gives a suggested timeline for resource development options for Nova Scotia. From this timeline, several major themes for long-range resource procurement emerge, defined by the major generation technologies after 2013 and the ‘export/import” bias of the developed wind installed generation. Table 5-1 below lists alternative resource scenario development plans for two snapshot years - 2013 and 2020. These plans are based on meeting the RES using Nova Scotia domestic resources until 2013. After 2013, Nova Scotia and/or external resources are considered to meet the GHG emission caps. Wind Development Scenarios are taken from the Wind Integration Study Report Figure 5-1 and Table 5-1 and for later analysis since that report contained energy production data. Section 5.2.1 outlines transmission requirements from the latest 10 Year Outlook report produced by the NS System Operator.

Table 5-1 Alternative Resource Scenario Development Plans

2013: Meeting RES by NS domestic resources	
SC1-M	Wind Development around transmission corridor
SC2-M	Wind Development is concentrated in Eastern part of Nova Scotia
SC3-M	Wind Development is concentrated in Western part of Nova Scotia
2020: Meeting GHG Emission Caps by NS domestic resources	
SC1-L	RES is met by Wind Energy
SC2-L	RES is met by Wind and Tidal Energy
2020: Meeting GHG Emission Caps by NS domestic resources & export	
SC3-L	Wind Energy developed to meet RES + Export
SC4-L	Wind & Tidal Energy developed to meet RES + Export
2020: Objective Meeting GHG Emission Caps by NS domestic resources & Lower Churchill	
SC5-L	Wind Energy and Lower Churchill
SC6-L	Wind Energy, Tidal Energy, and Lower Churchill
2020: Objective Meeting GHG Emission Caps by NS domestic resources & Point Lepreau II	
SC7-L	Wind Energy + Point Lepreau
SC8-L	Wind Energy +Tidal Energy + Point Lepreau

Figure 5-1 Potential System Development Opportunities Timeline



Scenario	Objective	Nova Scotia		External	
		Wind	Tidal*	LC	PT#2
SC1-L	Wind to meet RES&GHG	781	0	0	0
SC2-L	Wind& Tidal to meet RES&GHG	581	200	0	0
SC3-L	Wind and tidal to meeting RES&GHG	581	600	0	0
SC4-L	Wind &Tidal to meet RES&GHG+export	781	600	0	0
SC5-L	Wind + LC Import to meet GHG	581	0	750	0
SC6-L	Wind + Tidal+LC Import to meet GHG	581	600	750	0
SC7-L	Wind + PT2 Import to meet GHG	581	0	0	200
SC8-L	Wind+PT2 Import to meet GHG	581	0	0	200

	West	Valley	Truro	Pictou	Canso Strai	Sydney
2010 Base	31.2	32.3	82.1	112.6	22.8	15.6
SC1-M	61.2	111.9	117.5	142.7	110.9	36.3
SC2-M	31.2	32.3	82.1	112.6	120	199.8
SC3-M	295	32.3	82.1	112.6	22.8	15.6

	West	Valley	Truro	Pictou	Canso Strait	Sydney
2010 Base	31.2	32.3	82.1	112.6	22.8	15.6

5.2 Transmission Requirements for Blocks of Power

Costs for transmitting blocks of Wind and Tidal Power sources, as well as other sources that may be considered including imports, are shown in this Section.

5.2.1 Wind Power Interconnection

Figure 5-2 (from the 2009 Transmission Outlook Report) shows as an example, eight potential good Wind Development areas that are geographically apart, for the purpose of estimating the required transmission to the load centre. The amount of transmission that is required to bring the power to the load centre at Halifax will depend on the available room on the existing transmission lines and the amount of power to be transmitted and the distance to the load centre. The variability of Wind Power means that the changes in wind power output needs to be balanced by other resources on a minute by minute basis. Resources needed to balance Wind Power should be located such that the overall system security is maintained.

Wind Generation additions of 100 to 150 MW in Area 1 (South Nova), Area 3 (Upper Annapolis), or Area 4 (Halifax Metro) would require new transmission investments at an estimated cost in the range of tens of millions of dollars[†] in each case. Smaller blocks (< 30 MW) of new generation would likely face much lower transmission costs in each case. 230 kV and 138 kV transmission lines extend well into Area 1 (South Nova) and there is spare transmission capacity between Milton and Halifax. Transmission lines south of Milton would need to be added or upgraded to accommodate the 100 to 150 MW block of generation. Similarly, transmission lines extend well into Area 3 (Upper Annapolis Valley) and some transmission line upgrades will be required to accommodate the 100 to 150 MW block of generation. Area 4 (Metro Halifax) has 138 kV lines extending into the area but additions and upgrades would be required, resulting in costs in the tens of millions of dollars. Smaller blocks (< 30 MW) of new generation would likely face much lower transmission costs in each case.

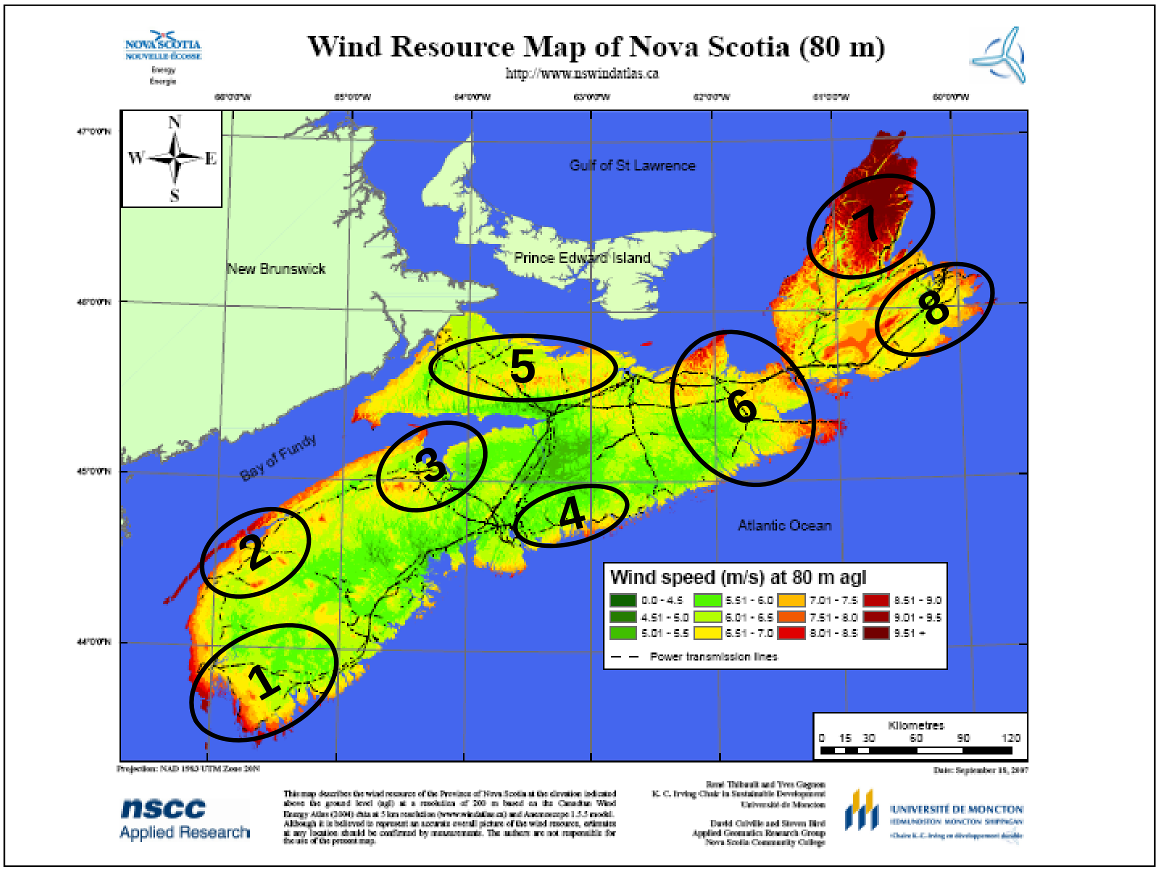
Generation blocks of 100 to 150 MW in Area 5 in Northern NS would require new local 138 kV transmission lines and the upgrade of an existing 230 kV line to 345 kV into Halifax with a total estimated cost in the range of $100 Million. The power from generation additions in Areas 6 to 8 would be required to be transmitted over the existing high voltage 230 kV and 345 kV grid that is already near its transfer limit. Generation blocks of 100 to 150 MW in Area 6 (Canso Strait) would require new 345 kV transmission lines and path upgrades to Halifax amounting to about $200 - $250 Million. The development of 150 to 250 MW of Cape Breton wind generation would also trigger the aforementioned new 345 kV lines, and in addition, new transmission lines into Cape Breton.

In summary, small blocks of generation can likely be accommodated in South Nova, Upper Annapolis and Metro (<30 MW) areas, while larger blocks of generation in these areas (100 to 150

[†] All transmission facilities and estimated associated costs are indicative figures presented only to facilitate understanding of the level of capital needed to realize such potential transmission options.

MW) would require estimated transmission costing in the range of $50 Million. Other areas would require transmission costing in the hundreds of millions of dollars to transmit 100 MW or larger blocks of generation.

Figure 5-2 Nova Scotia Wind Resource Map



5.2.2 60 MW Biomass - Cape Breton Strait Area Scenario

Assuming the east-west reinforcements discussed for Areas 6 through 8 are not constructed first, the 60 MW Biomass – Cape Breton Strait would require an additional line crossing of the Strait of Canso. This additional line crossing would eliminate the double circuit contingency limit. A bus reconfiguration at NSPI's Onslow 345 kV EHV substation, an upgrade of a 138 kV line terminal at NSPI's Trenton substation, and the addition of switched capacitors at NSPI's Brushy Hill substation would also be required. Costs would be under $50 Million.

5.2.3 Large Natural Gas Generator (250MW – 350MW) Expansion Scenario

- **Eastern Shore/Point Tupper Natural Gas Generator Scenario**

  Substation expansions would take place at Point Tupper and Port Hastings including the addition of a 345/230 kV transformer at Port Hastings. A 345/138 kV substation would be established at Spider Lake. A new 230 kV circuit would be required from Point Tupper to Port Hastings, and a 345 kV circuit would be required between Port Hastings and Spider Lake. Costs would be in the range of $200 Million.

- **Metro Large Natural Gas Generator Scenario**

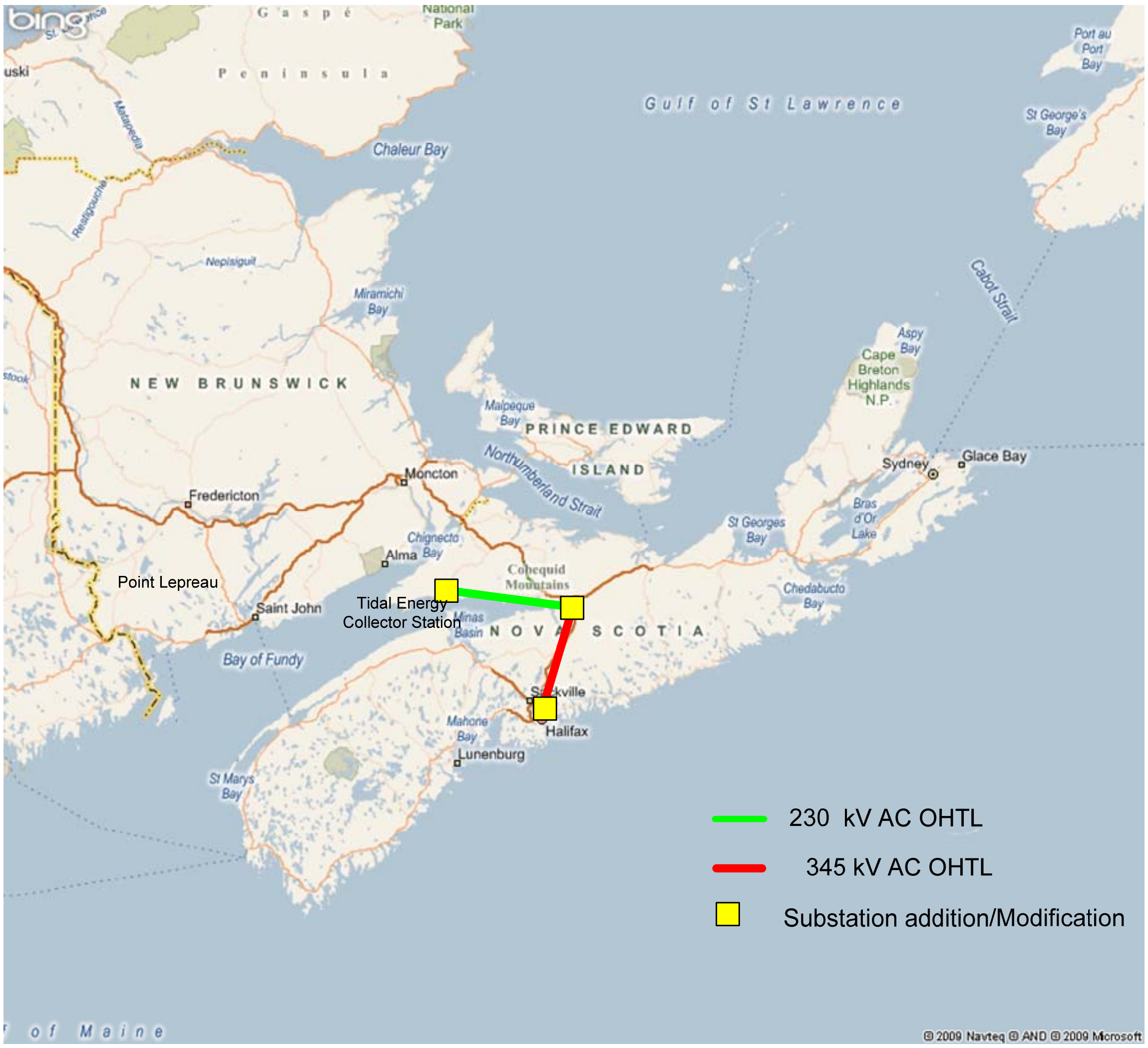
  Development of a 138 kV substation at Spider Lake, to terminate two existing Dartmouth 138 kV circuits along with increasing the conductor size on two existing Dartmouth circuits will be required. A new 138 kV circuit will be required from Spider Lake to Sackville, as well as a high capacity line from Tufts Cove to Brushy Hill. In addition, substation modifications will take place at Tufts Cove and Brushy Hill. Costs would be in the range of $50 Million.

For contingency loss of a large generator in the above mentioned scenarios, the NS-NB inter-tie may require reinforcement depending on potential unit size.

5.2.4 Tidal Power – Bay of Fundy

No studies have been carried out so far to estimate the transmission requirement and the cost of bringing the tidal power from Bay of Fundy down to the Halifax area. Conceptually, this would require the development of a collector station near Bay of Fundy along with associated supporting facilities, and a 230 kV or 345 kV line to connect Tidal Power from the collection point to Onslow and then down to Halifax area, if the tidal power displaced expensive Natural Gas generation in Halifax. It is estimated that costs would be under $100 Million. Feasibility studies and engineering work would be required to determine the additional costs to connect the tidal power generators to the collector station. Figure 5-3 shows the transmission development required to facilitate tidal power integration.

Figure 5-3 Transmission Development to Facilitate Tidal Power



5.2.5 Large Import from the Lower Churchill Development

Studies have not been carried out to estimate the transmission requirements and the cost associated with importing 300 MW or more from Lower Churchill. One concept is to transmit the power using HVDC submarine cable from Newfoundland to Cape Breton along with overhead DC transmission from Cape Breton to Onslow to Brushy Hill. An existing 230 kV circuit would be converted to 345 kV to provide a 345 kV transmission connection between Onslow and Brushy

Hill. A 345 kV ring bus would be established at Hopewell and a new 345 kV transmission would be constructed between Hopewell and the Metro Halifax area. It is anticipated that additional export of energy from Newfoundland through Nova Scotia would require a second transmission intertie between Nova Scotia and New Brunswick and transmission reinforcement of the New Brunswick transmission grid. Further studies will be required to judge the technical and economic feasibility of this alternative. If it is assumed that the power is priced and delivered to Nova Scotia at Onslow on the HVDC system, then the internal transmission costs would be in the order of $300 Million. Figure 5-4 illustrates the transmission requirements to facilitate Lower Churchill Import. The estimated cost of such transmission would be $800 Million to $1.2 Billion.

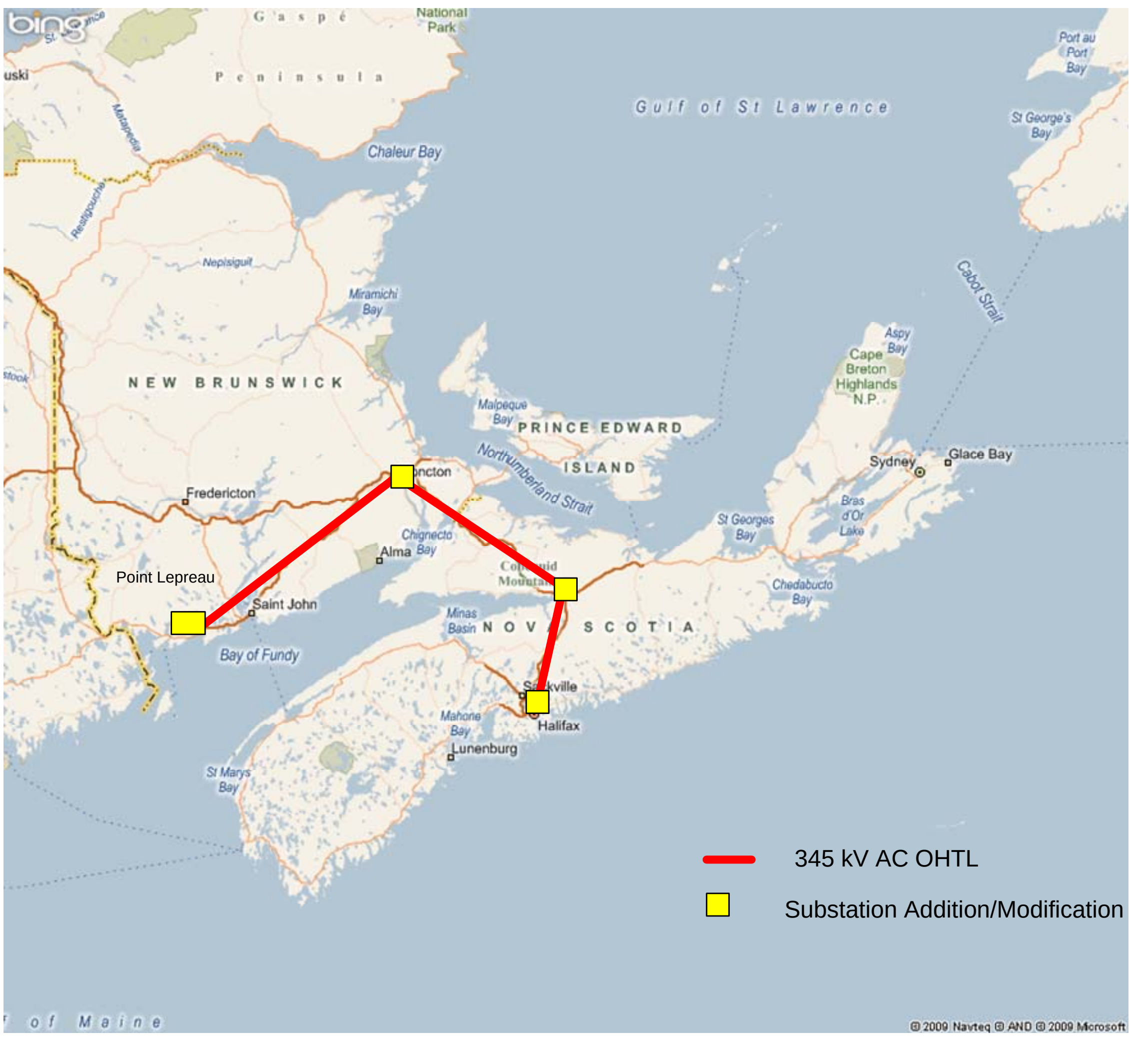
Figure 5-4 Illustrations of Transmission Requirements for Lower Churchill Imports

5.2.6 300 MW Import from Point Lepreau II

Studies have not been carried out to estimate the transmission requirements and the cost associated with importing 300 MW or more from Pt Lepreau II. A second 345 kV transmission circuit would be required between Onslow and Point Lepreau. An existing 230 kV circuit would be uprated to 345 kV to provide a 345 kV transmission interconnection between Onslow and Brushy Hill along with increased reactive compensation at Brushy Hill. In addition a 345 kV ring bus would be established at Hopewell and a 345 kV circuit would be constructed from Hopewell to the Metro area. Total transmission costs are on the range $200-$250 Million for the 2nd 345 kV interconnection and Nova Scotia upgrades assuming that the delivered price is at the border with New Brunswick. This price does not include the cost of transmission upgrades from the Saint John area to the NB-NS border, which would likely cost an additional $200 - $250 Million.

Figure 5-5 illustrates the transmission requirements to facilitate import from proposed Point Lepreau second nuclear reactor.

Figure 5-5 Illustrations of Transmission Requirements for Point Lepreau Imports



5.2.7 175 MW Compressed Air Energy Storage

Energy storage via compressed air storage and later release as electricity is suitable to balance the intermittent nature of wind energy. Some sites are located near the load center of Halifax, so that transmission costs would be in the range of $50 Million.

5.3 Medium Term Transmission System Development Plans

For the medium term scenarios to 2013, it is assumed that Wind Power will be the main resource that will be developed to meet the RES, and that 581 MW of Wind Power capacity will be installed. Biomass can also contribute toward this target. An installation of 60 MW of biomass with 85% capacity factor can provide up to 400 GWH, which can contribute effectively toward achieving the GHG emissions caps and RES targets. The feasibility of balancing the 581 MW of Wind Power using Nova Scotia system resources alone has been examined in the Nova Scotia Wind Integration Study. The impact of Wind forecast errors on the operation was not covered in the Nova Scotia Wind Integration Study report.

An increase in the tie-line capacity with New Brunswick would improve the capability of the Nova Scotia system to deal with all of the above issues. A second tie-line is required for most of the options and scenarios in the longer term, as outlined in Section 5.4. An advancement of the second tie-line would increase the ability of the Nova Scotia system to operate the increasing amount of Wind Power on the system and deal with wind forecast uncertainty.

Two transmission issues are discussed in this context: Transmission Economics related to location of Wind Farms; and requirements for the Second Tie-line. These issues are discussed below.

5.3.1 Transmission Economics Related to Location of Wind Farms

The economics of transmission development of good Wind Resources distant from the major load centers is evaluated by examining these three candidate transmission plans for a total of 581 MW of installed Wind Power from the Wind Integration Study. The data for the best known wind locations in the eastern portion of the system is taken from the Nova Scotia Wind Integration Study. The Wind Integration Study also evaluated two such location options for the 581 MW of Wind Power, and concluded that, after including the cost of transmission, differences in energy production and losses and etc, the option that included Wind in the Canso and East systems was more costly by $70 Million (net present value) than Wind Power of the same capacity near the load centre.

- **Option Sc1-M Maximizing Use of Existing Transmission Infrastructure**

- For this scenario, the incremental wind added from 2010 to 2013 is assumed to be developed around the existing transmission corridors and would use the existing transmission capacities remaining on these corridors. Special Protection Schemes (SPS) will be utilized to ensure system reliability and integrity if transmission transfer limits are violated. The use of SPS in Nova Scotia would require Northeast Power Coordinating Council (NPCC) review and approval. The Nova Scotia Wind Integration Study assumed the wind addition to occur at the main substations. The actual allocation of wind farms across the transmission corridor may result in the requirement for additional transmission facilities. Detailed system studies would be required to identify these required facilities.

- **Option Sc2-M Build Transmission to Access Best Wind Development**

- For this scenario, the incremental wind added from 2010 to 2013 is assumed to be developed in best wind location in the eastern side of the province at Canso Strait. The Wind Integration Study indicated that this would trigger building transmission lines which may cost about $260 Million. Integration of good wind regime in Sydney would require an additional 345 kV line from the Canso Strait to Sydney, which will likely result in doubling the cost estimate to about $500 Million.

- **Option Sc3-M Build Transmission to Access Wind Resources near Load Centers**

- For this scenario, the incremental wind added from 2010 to 2013 is assumed to be developed in west end of the province near the load centers at Halifax. The Wind Integration Study did not assign a transmission cost but it is expected that the cost would be in the tens of millions of dollars.

5.3.2 Transmission Requirements

Transmission requirements for the three mid-term scenarios are presented in Table 5-2.

Table 5-2 Mid-term Transmission Requirements

Scenario	Transmission Requirements	Comments
Sc1-M	No major additional transmission is required. Some incremental transmission may be required.	Utilization of SPS if need arises. Utilization of SPS should be reviewed and approved by NPCC
Sc2-M	Add one 345 kV circuit between Cape Breton and Halifax (as per the Hatch Study Report Option)	$200 Million in the Wind Integration Study
Sc3-M	Some transmission additions in West of Nova Scotia are possibly required	Tens of millions for incremental transmission addition

5.3.3 Second Tie-line Requirements

Wind is primarily an energy resource with power output levels varying with the strength of the wind. As such, the wind resource must be backed up by other generation with fast start-up times and high ramp rates. The Nova Scotia system has coal-fired generators which are basically not suited to daily on-off cycling duties. Apart from the need to follow the minute-to-minute and hour to hour variability, there is a need to be prepared for small or large changes in wind over several hours due to uncertainty in forecasts. This may not be critical in large systems with large tie lines, but can be a security issue in a small system with limited import/export capability.

Alternatively increased gas-fired resources may be an economic option in the short-term to balance out uncertainty in the wind resources.

In summary, when wind resources of over about 300 MW are developed, resource balancing for forecast variability and system control for uncertainty in forecasts need to be addressed by further study. Two solutions are back-up using gas-fired power plants and/or increased tie-line capacity.

5.4 Long Term Scenarios 2020

5.4.1 Nova Scotia Domestic Resources (SC1-L & SC2-L)

In these scenarios, it is assumed that the RES and GHG emission caps will be met by depending on local generation resources. The target will be met by depending on either wind resource alone, or by a mix of wind, biomass and tidal energy.

Possible Transmission Requirements:

- A 230 kV or 345 kV line from Cape Breton to Onslow and down to Brushy Hill;
- A 230 kV or 345 kV line to connect Tidal Power to Onslow; and
- A second intertie between NS-NB would be beneficial to meet Wind Power uncertainty

The potential transmission requirements for Nova Scotia domestic scenarios are presented in Table 5-3.

Table 5-3 Transmission Requirements for Domestic Resources

Scenario	230 kV Line	345 kV Line
SC1-L		CB x Onslow x Brushy 2nd NB-NS Intertie
SC2-L	Tidal x Onslow	2nd NB-NS Intertie

5.4.2 Domestic Resources and Exporting (SC3-L & SC4-L)

In these scenarios, it is assumed that the development of renewable resources inside Nova Scotia will exceed the RES and GHG emission cap requirements. It is assumed that the balance between the total renewable generation and the generation required to meet the RES will be exported to New England market via New Brunswick. In an optimistic scenario, the development of renewable resources will be large enough to justify a submarine cable to New England.

Possible Transmission Candidates:

- A 345 kV line from Cape Breton to Onslow and down to Brushy Hill;
- A second intertie between NS-NB;
- 345 kV parallel to the existing one, provided NB would enforce the transmission network around Moncton Area; and

- A submarine cable from Nova Scotia directly to New England, and sufficient firm capacity from possible wind, tidal + GT (At least 800 + MW of firm generation capacity is required to justify studying this option).

Transmission requirements for domestic resources and exporting scenarios are presented in Table 5-4.

Table 5-4 Transmission Requirements for Domestic Resources and Exporting

Scenario	230 kV Line	345 kV Line
SC3-L		CB x Onslow x Brushy 2nd NB-NS Intertie or NS-NE Export Line
SC34-L	Tidal x Onslow	CB x Onslow x Brushy 2nd NB-NS Intertie or NS-NE Export Line

5.4.3 Domestic Resources and LC Import (SC5-L & SC6-L)

In these scenarios, the assumption is that local renewable generation development will not be sufficient to meet the RES and GHG emission caps. The difference between the energy developed from domestic resources and the target will be met by importing from Lower Churchill.

Possible Transmission Candidates:

- Submarine DC cable from NFLD to land in Nova Scotia:
  - Cape Breton if the area coal generation is retired in place of the import and the spare transmission capacity is used to transfer this power to Halifax
  - Or to Onslow
- A second intertie between NS-NB:
  - 345 kV parallel to the existing one, provided NB would reinforce the transmission network around Moncton Area or
  - DC cable across the Bay of Fundy to NB
- A submarine Cable From Nova Scotia directly to New England:
  - Sufficient firm capacity from possible Wind, tidal + GT and Lower Churchill (At least 800+ MW of firm generation capacity is required to justify studying this option)

Transmission requirements for domestic resources and Lower Churchill import are presented in Table 5-5.

Table 5-5 Transmission Requirements for Domestic Resources and LC Import

Scenario	230 kV Line	SM Cable	345 kV Line
SC5-L		NFLD-NS SM Cable	2nd NB-NS Intertie or NS-NE Export Line
SC6-L	Tidal x Onslow	NFLD-NS SM Cable	2nd NB-NS Intertie or NS-NE Export Line

5.4.4 Domestic Resources and Point Lepreau II Import

In this scenario, the assumption is that local renewable generation development will not be sufficient to meet the GHG emission caps. The difference between the energy developed from domestic resources and the target will be met by importing from Point Lepreau's planned second generation unit. Table 5-6 presents the transmission requirements for domestic resources and Point Lepreau II import scenarios.

Table 5-6 Transmission Requirements for Domestic Resources and Pt. LP II Import

Scenario	230 kV Line	345 kV Line
SC7-L		2nd NB-NS Intertie
SC8-L	Tidal x Onslow	2nd NB-NS Intertie

5.5 Transmission Reinforcement Considerations

5.5.1 Second NB-NS Tie Configuration Issues:

- New Brunswick needs to significantly reinforce their Moncton area to support increased local loads in the future and firm transfers from New Brunswick to Nova Scotia, so building a new 345 kV line from Onslow to Salisbury/Moncton may not provide import benefits, unless New Brunswick also reinforces transmission in the Moncton area.

- If the second tie is built to support increased imports, then it is reasonable to assume that those increased imports are going to displace gas/oil-fired generation capacity in the Halifax load center. Therefore the second tie option from Moncton to Onslow must include reinforcement of the Onslow-South interface by new or uprated transmission from Onslow to Brushy Hill.

- If the second tie is built to support increased exports, then we must consider where those exports are coming from. If they are coming from east of Onslow, then that corridor must be reinforced to increase the Onslow Import limit.
- A second tie from Onslow to Salisbury will need concurrent transmission reinforcement in the New Brunswick system. Regional cooperation is important to achieve this goal.

5.5.2 Newfoundland-Nova Scotia Intertie Configuration Issues

Nalcor Energy is simultaneously pursuing several transmission corridors and customers. One of the main ideas under investigation is deploying 800 MW OH/SM HVDC link at +/- 450 kV from Gull Island to Soldiers Pond in Newfoundland, carrying on to a third terminal somewhere in the Canadian Maritimes, possibly terminating at Sydney, Onslow, or Salisbury. Realization of this option would also be coupled with the need for a second NS-NB intertie. The intertie would allow reliable operation of Nova Scotia system and provide opportunity for Lower Churchill to access markets in New Brunswick and New England.

The DC link from Newfoundland would only be landed in Sydney and it could either connect to the existing transmission system through a converter station there, or could continue as an overhead HVDC line and connect to the existing system through a converter station in the vicinity of Onslow. The latter option will provide better economics in terms of capital cost and expected transmission losses.

This intertie would necessitate another intertie with either NB or NE to export the balance and meet system reliability.

5.5.3 NS-NE HVDC Submarine Cable Consideration

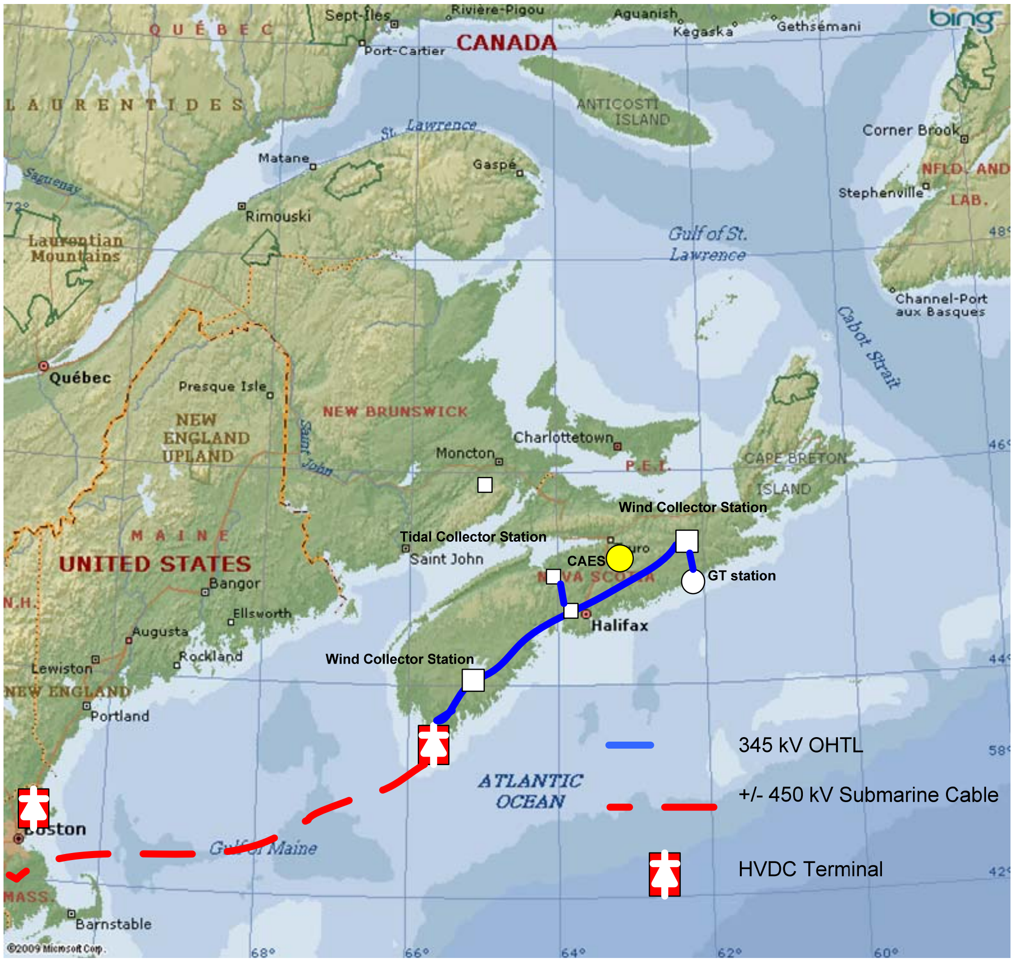
- Enough firm capacity (800+ MW) to justify the cable:
    - Wind Energy (1200 MW + for export)
    - Tidal Energy (300 – 600 MW for export)
    - GT or Combined Cycle (Balance Wind + Tidal)
    - Lower Churchill (400 MW)

- If HVDC from Newfoundland and Labrador had a converter station near Onslow, routing would be likely from there by HVDC overhead line and submarine cable

- NE landing point for cable and location of converter station such as to bypass NB-NE congestion

A double circuit 345 kV backbone transmission system to collect wind energy, tidal energy, gas turbine generation and possible Lower Churchill export will have to be built spanning Nova Scotia from East to the West. This line will be terminated at the first converter station on Nova Scotia. In this scenario, the CAES could be developed to provide needed balancing service for wind and tidal integration. Nova Scotia will be connected to the New England via HVDC submarine cable which should land somewhere near Boston. This concept would minimize the route of the submarine cable and allow tapping all renewable resources for exporting. Figure 5-6 illustrates the concept of the HVDC submarine cable to New England.

Figure 5-6 NS-NE HVDC Submarine Cable Consideration



5.5.4 345 kV Line between Cape Breton and Onslow (down to Brushy Hill)

This line would be needed to accommodate wind generation (beyond 2013 RES target) in the north-eastern part of Nova Scotia, for Scenarios 1 and 3. The portion between Onslow to Brushy Hill would be needed to accommodate Point Lepreau import and Tidal Energy Generation.

5.6 Evaluation of Transmission Options

5.6.1 Evaluation Criteria

These four major transmission projects may be considered in the medium and long term:

A) Nova Scotia internal transmission links to facilitate renewable resources, mainly eastern Wind Power development and Biomass (Medium to Long Term);

B) A Second Intertie with New Brunswick (Long Term advanced to Medium Term);

C) Importing transmission link (+/- 450 HVDC submarine cable & overhead line) from Newfoundland (Longer term); and

D) Intertie (+/- 450 HVDC submarine cable) with New England (Very Long Term).

The evaluation criteria for the transmission options are as follows:

- System Reliability Improvement and System Operation Flexibility;
- Future Flexibility to meet longer term GHG emission caps;
- Ability of the transmission to develop the best wind regimes and reduce variability;
- Import/Export capacity;
- Least Cost of Competing routings/ technology to meet an identified requirement; and
- Environmental Impacts related to land use for transmission.

5.6.2 Evaluation

Four major transmission developments may take place in Nova Scotia over the next few decades as outlined in Section 5.6.1 and in Table 5.7. These transmission options (A to D) relate to very different scenarios of resource development as outlined earlier. The impact of these transmission schemes are evaluated below.

Need

Transmission Scheme A is needed for major Eastern Wind Development (Canso Strait and/or Cape Breton), whereas Transmission Schemes B to D are for firm external transactions.

System Reliability Improvement and System Operation Flexibility

Two-way tie lines with the neighbouring systems will increase system reliability and operational and future flexibility to meet longer term GHG emission caps. Transmission Scheme A will improve the capacity to reduce variability of Wind Resources by geographical diversity; however it was shown earlier from the Wind Integration Study that it may not be economic to make large transmission investments to reach the best wind resource areas in the east.

Import/Export capacity

Transmission Schemes B to D have import capability but Schemes B and D can have advantages of two way transfers with large systems. The Least Cost alternative of competing routings/ technology would be determined based on distance, terrain and meeting the amount of power exchange.

Undersea routings will favour HVDC technology and the sink or source of power should be connected to the load centre. AC technology would favour 345 kV transmission, as this is an extension of the current Nova Scotia and New Brunswick standard for transmission of blocks of power. For large exports to New England, an undersea cable connection would bypass New Brunswick and connect directly with major load centres near Boston.

Environmental Impacts related to land use for transmission

Most options would require new transmission routes of over 100 km, although several routings are undersea.

Table 5-7 Evaluation of Major Transmission Options

Criteria	A)Transmission Reinforcement in Eastern N.S	B) Second Intertie to N.B	C) Intertie from NFLD	D) Intertie to N.E	Summary
Need	Needed for major Eastern Wind Development (Canso Strait and/or Cape Breton)	Needed for Major Import or Export Options but desirable to advance to the medium term for system security	Import Power Contract from NFLD delivered as AC power likely at Onslow	Export of Large Block of Power to New England (near Boston) by undersea HVDC Cable	These transmission schemes are **major** developments. Other transmission requirements are not included.
System Reliability Improvement	This reinforcement would alleviate the need for Special Protection Schemes required to maintain system reliable operation under high wind penetration scenario in the eastern part of Nova Scotia	Such an intertie would increase the NS system security in the short and long term	This is a one-way tie line for import of power. Contingency loss of this major import source needs to be covered.	This is a one-way tie line for export of power in the long term and could be a two way tie and would the improve NS security.	Two way interties will increase NS system Security especially with intermittent power sources
System flexibility	Some moderate improvement; flexibility to locate larger amount of wind resources	Increases NS system Flexibility particularly with intermittent power sources	No known major improvement	Increases NS system Flexibility especially with intermittent power sources	
Import/Export capacity	No major improvement	Facilitates Import/Export	Facilitates Import	Facilitates Import/Export	
Cost/Routings/ Technology	$200-$250 Million / new ROW parallel to the existing routes / 345 kV AC OHTL	$200 - $ 250 Million/ new ROW parallel to the existing NS-NB intertie / AC 345 kV AC OHTL. Additional $200-250$ Million for required upgrade in NB side	$800 – $1.2 Billion, +/- 450 kV HVDC Submarine Cable- up to 800 MVA Thermal rating 1000 MVA	$2.0-$3.0 Billion, +/- 450 kV HVDC Submarine Cable up to at least 1000 MVA	HVDC power import or export is best from/to the load center
NS Land use for transmission	Could require 300 km new ROW for 345 kV lines	Acquire about 100 km new ROW for 345 kV line in NS plus more in NB	Overhead about 200 km from Halifax area to the coast then Submarine cable	Overhead 300 km from the eastern shore to Onslow as HVDC	Routes could follow existing corridors
Future Flexibility to meet longer term GHG emission caps	flexibility to locate larger amount of wind resources	Increases NS system Flexibility especially with intermittent power sources	Yes	Yes	
Develop the best wind regimes and reduce variability	Provides for the development of Wind Power across the system and this reduces variability	Some improvement, if balancing power could be obtained from NB	No major improvement	No major improvement	

5.7 Conclusions and Recommendations

5.7.1 Conclusions

The transmission requirements for the mid to longer term will depend mainly upon the resource development as a result of aggressive government GHG policies in Nova Scotia and the region including New England. The northern regions are blessed with ample sources of renewable resources, and New England and the US in general will need such resources in the mid to longer term. Potential transmission schemes for major power transfers have been presented and evaluated in this report. Major planning and operating studies are required to fully understand the requirements of such power systems.

Mid-Term Transmission Development

- The Nova Scotia Wind Integration study was an indicative study, as the study did not consider the uncertainty of wind power. Another study is needed to capture and deal with this issue. Nova Scotia System islanding with large amounts of wind generation imposes greater risk of utilization of load shedding. A second intertie would mitigate such risks. Concurrent system reinforcement to the New Brunswick system would be necessary.

- Increased level of wind penetration may result in dispatching available resources ignoring the merit order, and will lead to a dispatch pattern which is more complicated and expensive.

- The costs and benefits of the transmission costs to develop the best Wind Resources are required since it has been shown that there is an economic limit to reach the best wind resources.

- The use of 60 MW of biomass can guarantee about 400 GWH per year which would contribute to fulfilling RES and GHG emissions caps.

Long-Term Transmission Development

While all stakeholders agree that resource development in Nova Scotia must and will comply with the renewable energy target, they differ in the approach they believe will best achieve this goal. Some stakeholders believe the 2020 GHG emission caps can be achieved using domestic resources, while other stakeholders have a more optimistic view regarding the future of renewable resource development and believe the renewable energy resources can be developed to a level which permits meeting the 2020 GHG emission caps and exporting to neighbouring system. Other stakeholders believe that the most economical solution to increase the contribution of renewable energy would be by mixed utilization of domestic resources and imported power from Lower Churchill, or Point Lepreau II nuclear generation. Pursuing some of these different visions would require further development of government policy in Nova Scotia as well as other provinces and states, and possibly nationally, in both the US and Canada.

- At this stage, there is no clear policy regarding retirement of coal fired plants. The analysis presented in this section assumes that the coal fired plants under all scenarios will serve Nova Scotia for years beyond the current timeline considered in this study.

- A second intertie between Nova Scotia and New Brunswick would be required under all scenarios (self-sufficient, exporting, and importing scenarios), with varying degrees of urgency to the requirement under different scenarios. The exact timing of the second intertie would largely depend on a number of different factors: speed of development of renewable resources, development in Point Lepreau and Lower Churchill, New Brunswick system reinforcement, and the evolving market structure in the region.

- The configuration for the second intertie would depend on the justification of the second line (reliability vs. economic operation) and the New Brunswick system reinforcement in Moncton Area.

- A 345 kV line from Cape Breton and Onslow and then down to Brushy Hills would depend on:

    - Retirement policy of coal power plants;
    - Development of Lower Churchill, and ultimate destination of supply from Lower Churchill into the Canadian Maritimes; and
    - The timing of the development of Wind resources in the eastern part of Nova Scotia.

5.7.2 Recommendations

- A study of the power system operation for operation with the higher amounts of wind power is required so that any issues can be resolved.

- Identify the locations with the combination of the best wind regimes and low transmission costs, and promote wind power development in those areas.

- Gain the advantages of advancing the additional Nova Scotia tie-line to the medium term. Establish the best configuration, technology and transmission requirements, costs and schedule of the additional tie-line including regional requirements.

- Initiate a Maritime Regional Transmission Planning function to study and plan transmission systems on a regional basis for mutual benefit. Longer term planning would study the transmission implications of clean resource import/export opportunities.

6. System Operator Options

This section of the report addresses the institutional arrangements involved in the operation of the Nova Scotia electricity system. In the interest of addressing all relevant issues related to these institutional arrangements, the discussion covers some aspects of the commercial structure of the regional electricity system beyond the real-time market which is directly associated with system operations. These broader commercial factors are introduced since they will be significant in deciding how best to meet Nova Scotia's electricity policy objectives, and therefore have some bearing on decisions both for transmission developments and system operator arrangements. However, decisions on the broader regional commercial factors will require investigations and analysis that are beyond the scope of this report.

This report was prepared over several months prior to the October 29, 2009 announcement of a potential transaction that would result in substantially all of New Brunswick's electricity system being owned and operated as a subsidiary of Hydro-Québec. As proposed, this transaction could have a significant impact on future directions for Nova Scotia's electricity sector and systems operations. However, while some comments on these impacts are included, no attempt has been made to fully assess either the proposed transaction, or its impacts.

6.1 Role of System Operator

6.1.1 General practice

Under the traditional vertically integrated monopoly structure, typical for electricity service across Canada until recently, the system operator function was established as a small group or department embedded within the utility. The system operator's main responsibility was to operate the transmission system and the connected installed generation in a safe and reliable manner. In the mid 1990s, that role started to be transformed as several provinces and many US states followed the global trend of placing more weight on market forces in their electricity systems. In a competitively restructured electricity system, generators competed to supply while the transmission system became an open-access common carrier. As a result, it became necessary for system operators to be independent of any utility interests to ensure that access to the transmission system was provided fairly and objectively[3].

6.1.2 International Trade

Canada has for many decades been a net electricity exporter to the US, mainly due to the availability of low cost hydroelectric resources; both countries realize commercial benefits and improved electric reliability through trade. It has therefore been important to many US and most Canadian electricity systems to ensure that competitive markets and open access transmission were introduced in a fashion that facilitated continued international trade. The US has also focussed on augmenting inter-regional trade, the major initiative being to expand the size of

[3] However, in the US, FERC allowed for transmission functions to remain within vertically integrated utilities, as long as they were functionally unbundled and were non-discriminatory in their actions, per the Order 889 Standards of Conduct.

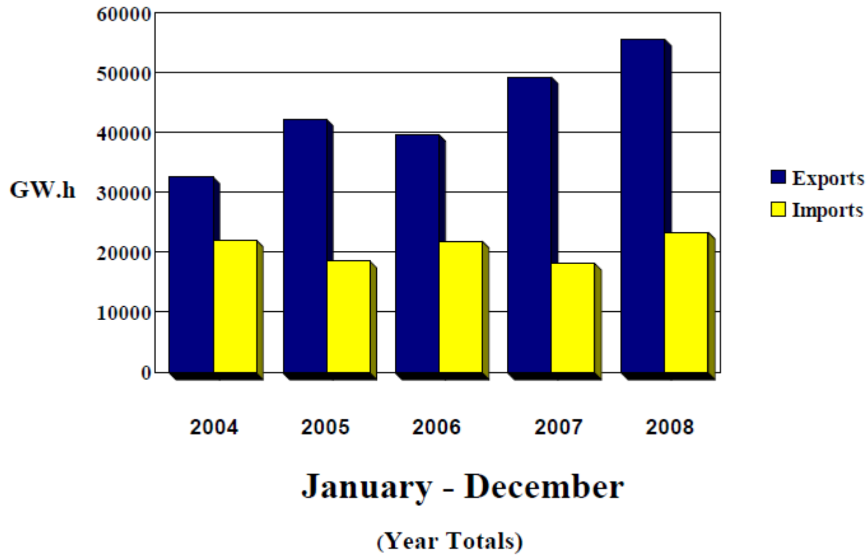
wholesale markets by mandating open access to transmission systems nationally. Since the issuance of Order 2000 in 1999, the US Federal Energy Regulatory Commission (FERC) has promoted the formation of Regional Transmission Organizations (RTOs) as the mechanism to achieve wholesale access, thus enabling US consumers to obtain lower cost power from other regions.

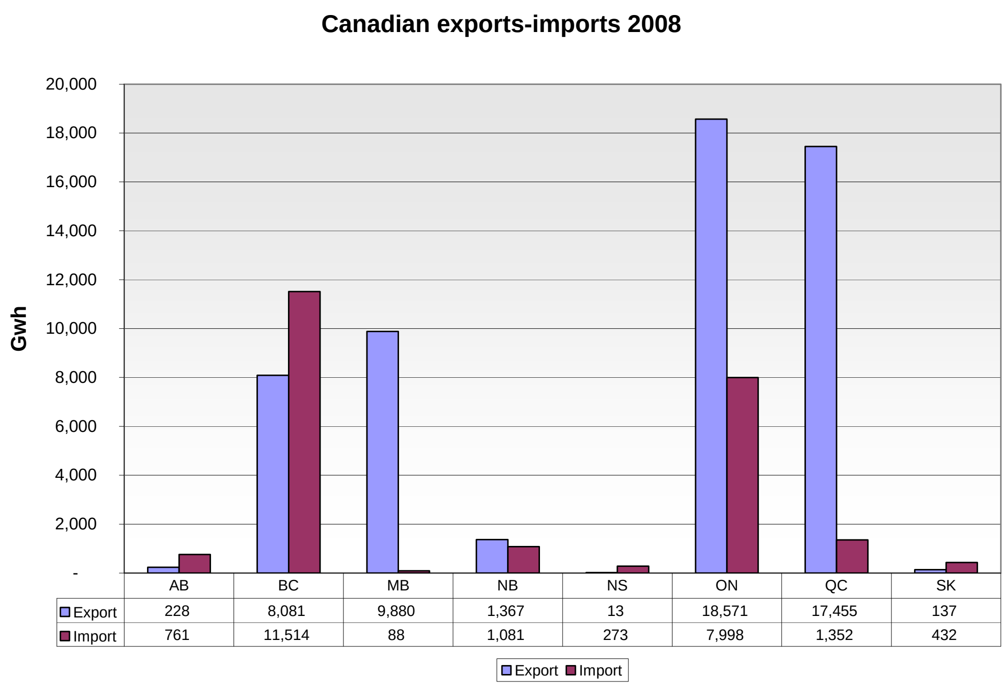
While FERC has no jurisdiction in Canada, its policies have an impact on Canadian entities that trade with the US. In particular, FERC has a reciprocity provision which requires that any entity licensed to use open-access transmission in the US must provide similar open access to its own transmission system. Most Canadian electricity systems, even those that do not have any internal competitive market, have adopted an open-access transmission system to ensure that their utilities could continue to access US markets over the US transmission system.

Some have observed that NAFTA provisions requiring non-discriminatory treatment (i.e. all users of each system must be treated the same) should override FERC provisions requiring reciprocal treatment (i.e. all systems must treat users the same way). However, the fact is that no Canadian entity has tested this through a NAFTA appeal, and all have instead simply put in place an open-access transmission system as the minimum requirement to obtain a FERC license to move their electricity over US transmission systems.

Figure 6-1 shows Canadian export-import amounts for the period 2004-2008. In 2008, exports amounted to 55,732 GWh and imports amounted to 23,499 GWh. On the other hand, connections between provinces are typically not as strong as north-south connections. In some cases, these interconnections are not developed sufficiently to optimize inter-provincial synergies. It is noteworthy that some provinces, particularly British Columbia and New Brunswick engage in significant electricity trade in both directions. This is indicative of active “buy low, sell high” trading based on playing off their system resources against market opportunities. In contrast, other provinces, particularly Québec and Manitoba, are heavy exporters and import very little, indicating that international trade is on the basis of fixed long-term commitments.

Figure 6-1 Canadian Exports-Imports





	AB	BC	MB	NB	NS	ON	QC	SK
Export	228	8,081	9,880	1,367	13	18,571	17,455	137
Import	761	11,514	88	1,081	273	7,998	1,352	432

6.1.3 Electricity Policy and Regulation

With respect to the development of electricity policy and regulatory oversight, the Canadian federal government (through the National Energy Board) has jurisdiction over electricity exports from Canada, and international and designated inter-provincial power lines. The provinces and territories have jurisdiction over generation, transmission and distribution of electricity within their boundaries, including restructuring initiatives and electricity prices. In contrast to this, jurisdiction for many of these matters in the US rests with the US Department of Energy and FERC. The US Department of Energy has jurisdiction over international power lines, and administers the issuance of Presidential Permits as the legal instrument that authorizes such projects. In the US, FERC has jurisdiction over all arrangements governing wholesale markets, such as power pools, contracts for the operation of transmission systems and other wholesale market control matters. FERC jurisdiction includes transmission operations, such as the requirement of equal access for all sellers and buyers in a given market. As a result of this, most of the powers exercised in the US by FERC are exercised in Canada by provincial agencies.

Because there is no federal authority in Canada to compel uniformity in electricity policy, provincial boundaries still mark the limits of electricity markets. In contrast, regional electricity markets in the US often transcend state boundaries. Of course, since most provinces are much larger in area than most states, the geographic outcome has not been significantly different between the countries. FERC has therefore been the de facto unifying influence in the restructuring of Canadian electricity systems. For example, to fulfill the FERC reciprocity requirement of open access, many provinces - including Nova Scotia - have based their open access transmission tariff (OATT) on the FERC pro forma OATT contained in Orders 888-889 (described below). As well, many provinces arrange their system operator functions in accordance with FERC requirements for independence. This too is the case for Nova Scotia.

In the US, despite the presence of significant amounts of government and consumer-owned generation, the electricity industry is characterized by the dominant presence of investor-owned utilities (IOUs) and the regulatory mechanisms that have evolved to control their monopoly franchises. In Canada, on the other hand, the industry has historically been dominated by Crown corporations which still enjoy full or quasi monopolies. Historically, these corporations were generally not subject to formal regulation, but rather they were informally controlled by the provincial government. However, in response to the growing public desire for transparency and a voice in major public expenditures, each of these Crown utilities is now subject to some degree of formal regulation.

6.1.4 Restructuring

As mentioned previously, over the past decade, many North American jurisdictions have restructured their electricity supply arrangements to varying degrees. The intention of restructuring is to separate (or unbundle) the generation, transmission and distribution functions and promote competition in the generation, wholesale and retail sectors. The general expectation has been that competition will encourage efficiencies and lead to lower costs. Wholesale access to transmission grids enables local distribution companies, or other large buyers, to use the grid to purchase electricity from the most competitive generation sources. Finally, retail access could economically benefit consumers as a result of having choice among suppliers.

The extent of restructuring in Canada varies across the country. Alberta and Ontario have moved the furthest in restructuring toward fully competitive markets. British Columbia, Québec and New Brunswick have wholesale access and retail access to large industrial users, while Manitoba, Saskatchewan and Nova Scotia allow wholesale access only. As a result of these changes, the roles of system operators have been significantly augmented beyond their traditional scope of overseeing security and reliability.

It will become evident that there are many different restructured arrangements in use and that each have strengths and weaknesses. The degree of success achieved with restructuring also covers a wide spectrum. While there are many blueprints to follow and lessons to be learned from others' experiences, each jurisdiction usually finds that it needs to follow its own approach to accommodate both a starting point and policy objectives which are unique.

Wholesale Markets, Bilateral Contracts and the Pool Model

In several provinces, the restructured system operators have taken on new functions such as the administering the OATT, administering the market rules, running the real-time wholesale market, procuring ancillary services (see description in Appendix D), providing settlement services, forecasting day-ahead generation commitments and holding auctions for rights to transmission system transfer capacity.

The relationship between the various parts of a complete electricity marketplace is illustrated in Figure 6-2. Of particular importance, it must be noted that the wholesale market spans a range of timescales from real-time spot market to long-term forward market. Two basic models have evolved for the design of the real-time part of the wholesale electricity market: The *bilateral contracts model* and the *pool model*.

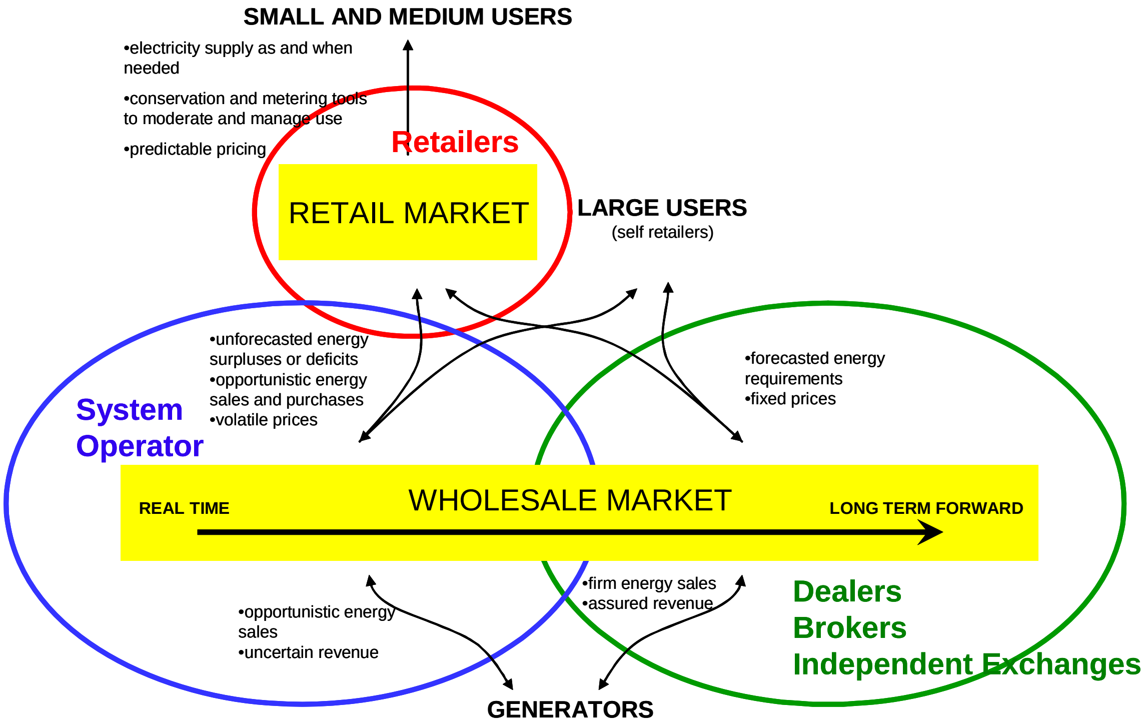
Under the *bilateral contracts model*, individual market participants and/or traders conclude physical contracts for the sale and purchase of electricity in different timeframes (yearly, monthly, hourly). The price under these contracts is confidential and the only information provided to the system operator (normally a day in advance on an hourly basis) are the points of injection and withdrawal of the energy and the size of the transaction. Transmission reservations and service are arranged with the system operator for a fee, including payments for those ancillary services that the contracting parties cannot self-supply. The system operator separately procures ancillary services through tenders and/or via a real-time market. In Canada the majority of provinces have adopted this model (e.g. NS, NB, QC, MB, SK, BC) as it is the minimum form for compatibility with FERC's Order 888-889.

Brokers or traders can facilitate the bilateral trade, and in cases where the number of participants is large, a voluntary power exchange can act as counterparty for trade and offer clearing services[4]. One of the shortcomings of this model is that a market price in which

[4] Many power exchanges exist in Europe where the bilateral contracts model is more common than in North America. The largest exchange is NordPool which covers a very large geographical area including five countries (Norway, Sweden, Finland, Denmark and parts of Germany)

participants have confidence requires market "liquidity" (i.e. an ongoing volume of trading sufficiently high assuring buyers and sellers that they can buy or sell at will). This is only likely to occur if a power exchange is established, since by facilitating anonymous trading, an exchange greatly reduces the overhead cost of each transaction, simplifies trading by means of standardized contracts, reduces counterparty risk and therefore facilitates the non-discriminatory participation of players regardless of the size of their transactions. Inadequate liquidity undermines the confidence of market participants and inhibits the evolution of forward markets.

Figure 6-2 Electricity Marketplace Components



In contrast, the *pool model* relies on the system operator running a wholesale market, with either one (real-time) or two (day-ahead plus real-time) settlements, plus a market for operating reserves. Generators/importers submit to the system operator offers to sell energy and exporters/large customers submit bids to buy energy, while the system operator determines the market clearing price on the basis of the quantities to be produced and consumed at the various submitted prices. There could be a single market price for the whole system or different prices for a number of predefined nodes or zones within the system. All producers and consumers get paid or pay the applicable price established by the system operator. Along with their bids for energy and operating reserves, generators also submit technical characteristics of their units (e.g. up and down ramp, minimum up-time) plus other costs (e.g. no-load costs, start-up costs) which are paid by market participants along with other costs incurred by the system operator such as out-of-merit dispatch, must-run generation, etc.

Transmission access is implicit in this model. This means that there is no need to reserve transmission capacity since all accepted offers/bids have guaranteed access to transmission. In this model, all the energy generated and used goes through the system operator, therefore the market clearing price is a comprehensive reflection of its value.

The forward market under the pool model results from parties entering into financial contracts or hedges to guard them against volatility of the real-time energy price. The most basic financial contract is the contract for differences, where the producer and the consumer agree on a fixed price, and each party reimburses the other for the “difference” between the market and the contract price so as to maintain the financial transfer as per the contract. In Canada, only Alberta and Ontario have adopted the pool model.

To illustrate the complexities associated with the new roles of a system operator as facilitator of a wholesale market, the Ontario and Alberta real-time markets are described in Appendix D.

Renewable Energy

More recently, many provinces have implemented policies to encourage IPPs to build new renewable generation projects. In many cases, this has created a large number of new generation system connection requests that the system operators and the “wires” companies (transmitters and distributors) must analyze on a case-by-case basis under tight deadlines. Frequently this requirement has strained the scarce resources of the system operators and wires companies, and has resulted in delays and the need to outsource these studies. The complexity and volume of work is increased by the fact that in many situations, the feasibility of providing system access for several projects are interdependent, yet commercial decisions on each project are separate and confidential.

Also, as is discussed in the previous sections of this study, the increased penetration of intermittent generation such as wind is bringing new challenges to the system operators, related to the additional complexities of keeping supply continuously in balance with load requirements. The greater use of intermittent generation has also opened up a discussion of the optimal geographic size of a “pool” or “control area” for balancing. That, in turn, raises questions about the potential for a regional scope for system operators. As discussed below, there are important benefits of “regionalizing” wind dispatch and balancing, since this would facilitate the installation of increased amounts of wind generation.

Reliability and NERC

All interconnected Canadian utilities are a part of the continent-wide arrangements for ensuring reliability, which is led by NERC. NERC operates through regional reliability councils, and utility members adhere to standards for planning and operating their systems. Among the standards are other responsibilities such as reporting of system adequacy forecasts, being a balancing authority, and reliability coordination (for a group of areas). As mentioned previously, Nova Scotia, along with all systems in the Maritimes region, Québec, Ontario and those in the north-eastern US, are members of the NPCC which is one of the regional reliability councils.

Following early sector reforms, inadequate levels of investment in transmission infrastructure in North America had been long recognized as a major issue. In the wake of the 14 August 2003 blackout which affected much of the northeastern US and southern Ontario, reliability of the interconnected North American bulk power system became a priority concern for both Canada and the US. *The Final Report of the Canada-US Task Force* outlined 46 recommendations to improve overall reliability and called for the establishment of mandatory reliability standards to replace the former system of voluntary standards. The US *Energy Policy Act, 2005*, responded to those recommendations by empowering FERC to enforce mandatory standards in the US, thereby following established practice of the provincial regulatory authorities in Canada.

Reliability standards are developed by the electricity industry using a balanced, open, fair and inclusive process managed by the NERC Standards Committee. The Committee is facilitated by NERC staff and comprised of representatives from many electric industry sectors. Proposed standards are reviewed and approved by the NERC Board of Trustees, which then submits the standards to FERC and Canadian provincial regulators for approval. Once approved by these statutory agencies, the standards become legally binding on all owners, operators and users of the bulk power system.

NERC has developed a *compliance and enforcement program* to improve the reliability of the bulk power system in North America. The program is designed to ensure that the right practices are in place so that the likelihood and severity of future system disturbances are substantially reduced. Regular and scheduled compliance audits, random spot checks, and specific investigations are used to implement the monitoring. NERC or the Regions may, at any time prior to the issuance of a notice of penalty by NERC, engage in a series of negotiations with the implicated user, owner or operator, giving the implicated entity an opportunity to settle any disputes or acknowledge the allegation and accept any associated penalties. When an agreement has been reached and approved by NERC's Board of Trustees Compliance Committee, NERC is obliged to provide the details of the investigation to FERC in the US, or to applicable authorities in Canada. At this point, the information becomes publicly available and will be posted to NERC's website. At least one Canadian province, Alberta, requires that the proceeds of any financial penalties remain in the province and be spent for the benefit of provincial electricity users.

FERC Orders

Historically, the electricity systems in North America began in municipalities and expanded to adjacent regions. Whether companies were private or public, they tended to focus on serving the customers in their service territories, with external trade and energy transfers being a secondary concern. One of the main factors that promoted restructuring in the US was that customers in higher cost service areas were unable to access power in lower cost service areas. To address the barriers to inter-regional trade, FERC released Orders 888 and 889 in April 1996 and Order 2000 in December 1999.

The purpose of FERC Order 888 is to promote wholesale competition through the provision of open access to transmission services on a non-discriminatory basis while Order 889 requires transmission owners/operators to create an Open Access Same-time Information System (OASIS). This system must provide information, among others, regarding available transmission capacity and prices. Since most control areas in the US continued to be operated by vertically integrated firms, there remained concerns about the "independence" of transmission owners and the potential for discrimination against independent generators and marketers seeking to use these transmission systems. To deal with this issue, Order 889 also required public utilities to implement standards of conduct to functionally separate transmission and unregulated wholesale power merchant functions to ensure that a vertically integrated transmission owner's wholesale market transactions are not advantaged by virtue of preferential access to information about the transmission network. Later FERC issued Order 890, which upheld many of the details of Orders 888/889 but also enhanced or revised some aspects

FERC Order 2000 established a framework for the creation of Regional Transmission Organizations (RTOs), composed of one or more transmission companies that would function as an integrated transmission entity. This structure is intended to promote competition in wholesale markets by providing non-discriminatory access to transmission, and to reduce the cost of transmission within the RTO area by eliminating the rate “pancaking” that results as each separate transmission company involved in a transfer adds on its separate charges.

Participation by transmission providers in an RTO is voluntary. FERC promotes RTOs in the US and encourages Canadian entities to participate. While the Canadian electricity industry generally recognizes the benefits of RTOs if they are properly implemented, concerns have been expressed by some stakeholders about the dilution of their control in a regional electricity system and that the cost involved could outweigh the benefits. While there are many instances of cooperation, no Canadian entities have so far joined a cross-border RTO. For example: Manitoba has a coordination agreement with the Midwest ISO; British Columbia has been participating in the development of the GridWest RTO; and Ontario cooperates with adjacent RTOs in the US Northeast and Midwest.

A more detailed description of the drivers behind FERC Orders 888-889 and 2000, their principles and minimum requirements can be found in Appendix D

6.1.5 Currently in Nova Scotia

Structure of the market

The current institutional arrangements in Nova Scotia are that NSPSO exists as a functionally unbundled part of NSPI as required under the Standards of Conduct since 2003. This was in accordance with the recommendations of the Electricity Market Governance Committee (EMGC) in 2003 and to meet the reciprocity requirements in New Brunswick. At that time, the policy objective was to create a level playing field for Nova Scotia businesses and residents with respect to other Canadian provinces and US states, and particularly with respect to New Brunswick, which had recently unbundled the vertically integrated monopoly.

In Nova Scotia, focus was placed on the wholesale electricity market, and decisions were made to leave untouched the retail marketplace. Both provinces adopted an OATT in accordance with the FERC reciprocity requirements discussed previously.

In Nova Scotia, the decision was made to limit participation in the demand side of the market only to buyers who are resellers. This definition excludes even large industrial electricity end-users and results in a marketplace where distribution utilities are the only eligible buyers. Since more than 98% of provincial electricity use is provided through the distribution unit of NSPI, and all the municipally owned distribution utilities elected to continue their past practice of buying wholesale from NSPI, the net result is that Nova Scotia is effectively a single buyer market with the NSPI distribution department being that buyer.

The market design in Nova Scotia provides for two distinct levels of competition to exist: competition in the bilateral energy market (wholesale to municipal distributors and import/export); and “competition on entry” for new supply investments through competitive RFP processes undertaken by NSPI in order that it can fulfill its default supply obligations to consumers and wholesale customers electing such supply. It is the “competition on entry” in response to RFPs that is being relied on for necessary investment in the near term.

The Nova Scotia Utility and Review Board (UARB) from time to time can request NSPI to update the Integrated Resource Plan defining the future generation, transmission, distribution and DSM projects. If new generation is necessary, NSPI issues an RFP which is open to all interested parties who meet its qualification requirements. To ensure the success of an RFP, NSPI would normally be required to submit a bid. However, in the case of the recent RFP to meet the provincial RES objectives, and in order to encourage participation of IPPs, NSPI was not allowed to bid on providing the first blocks of renewable generation.

A FERC 888 style OATT and a FERC 889 compliant standard of conduct has been implemented by NSPI laying the foundations for a bilateral contract market and achieving reciprocity for access to New Brunswick and US markets. The OATT came into effect on

November 1, 2005. The market rules were developed by the Department of Energy, with input from stakeholders and in January, 2007 the Minister of Energy delegated administration of the Market Rules to NSPSO.

NSPSO as an Independent Function

Given the relatively small size of the Nova Scotia system and the limited number of market participants, it was determined at the time of initial restructuring that the expense and complexity of establishing a system operator as a stand-alone entity was not justified. As a result, the current Nova Scotia System Operator function resides within an investor-owned utility. This has implications for any changes to NSPSO that separate it from NSPI, since such a change would effectively involve expropriation of NSPI property and possibly constructive dismissal of present NSPSO staff. The legal issues and cost effects of establishing a more independent NSPSO are therefore more significant than was the case in, for example, New Brunswick, where all the entities both before and after the split were publicly owned.

NSPSO is a part of the Customer Operations Division of NSPI, and its resources are allocated as part of the corporate budgeting process. Business plans for NSPSO are developed and resources are engaged and monitored throughout the year. The resources available to the NSPSO include NSPI employees and contractors.

Standards of Conduct (approved by UARB in 2003 and updated in 2005) are an integral element of functional independence and are based on the following principles:

- NSPI's Transmission group functions independently of NSPI's Wholesale Merchant group, and from its affiliates.
- Employees of NSPI's Wholesale Merchant group do not conduct transmission system operations or reliability functions.
- Transmission department employees treat all transmission customers on a non-discriminatory basis.
- OASIS (Open Access Service Information System) is the method for providing transmission information (NS OASIS is actually administered by NBSO)
- NSPI is permitted to share support employees and field and maintenance employees with its marketing groups and affiliates.
- In emergency circumstances affecting system reliability, the Standards may be suspended to allow any necessary staff to deal with the emergency.

Roles of NSPSO

The roles and responsibilities of NSPSO as required by the market rules are as follows:

Operation of the bulk electricity system: Operate safely and reliably the bulk transmission system according to NERC/NPCC reliability standards (implemented through NSPI membership in NPCC), UARB orders and Interconnection Agreement with NBSO, including:

- Manage requirements of load plus reserve to ensure continuous service;
- Perform generation dispatch using pre-approved schedules, with real-time adjustments for efficiency/reliability;
- Operate the system within established limits;
- Respond to system contingencies, and
- Control the flows on interconnecting lines with neighbouring systems in accordance with established schedules.

Operation of the wholesale market and administration of the Market Rules: Support the wholesale electricity market by promoting economic supply through competitive opportunity amongst eligible participants, in a non-discriminatory, transparent and efficient manner.

Reliability Planning: Produce periodic forecasts and assessments of system capacity and adequacy (18 month forecasts and assessment on a weekly basis and 10 year on a monthly basis). Produce triennial "5 year assessment" of the Maritime area jointly with the NBSO and Maritime Electric Company. Meet other requirements as per NPCC or as they arise.

System Planning: As required by the market rules, develop a 10-year plan (filed with the NSUARB) including: a) transmission plan; b) DSM programs operated by NSPI Customer Service division or others; c) NSPI generation planning for existing facilities (retirements, upgrades, refurbishment or life extensions); d) new generating facilities; e) new generating facilities planned by market participants or connection applicants other than NSPI; and f) requirements for additional DSM programs and / or generating capability (for energy or ancillary services). The plan must include all significant transmission system upgrades that are planned or expected to be required in service within 5 years of the plan completion date.

Administration of the OATT (on behalf of NSPI as Transmission Operator): Administer the OATT, including: a) file proposed amendments to the tariff with UARB; b) provide transmission service; c) provide Ancillary Services; d) operate the transmission system in accordance with the tariff; and e) schedule transactions on the interconnections between Nova Scotia and New Brunswick.

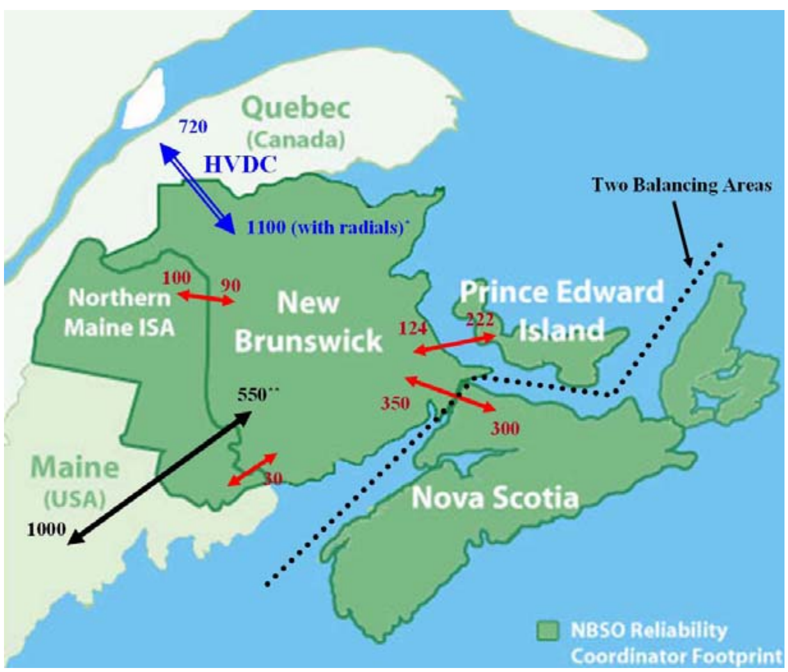
Administer the Generator Interconnection Procedures (GIP): Provide Interconnection Service and carry out interconnection studies, including retaining third party consultants to carry out studies. The GIP process managed by NSPSO is independent from the RFP process carried out by NSPI for the selection of renewable energy projects to comply with RES targets. Nova Scotia is like every other jurisdiction with both a FERC-based GIP and RES - the requirements of the GIP can make it time consuming to complete studies but projects cannot proceed until they are studied - even if they have contracts to meet RES requirements.

NSPI recognized this issue and filed for and received a temporary waiver of the GIP for the projects selected through the RFP process. That was specifically put in place to allow those projects with contracts to move through the GIP first - action taken to speed up the process of getting more independently owned generation on line. Subsequent to that, NSPI and NSPSO staff, together with stakeholders, reviewed and revised the GIP to streamline the process so it allows commercially ready projects to move through the process faster. NSPI has filed a revised GIP with the UARB.

6.1.6 Currently in Atlantic Canada and New England

The interconnected systems of New Brunswick, Nova Scotia, and Prince Edward Island provide 28.5 TWh of electrical energy annually with a peak demand of 5,600 MW within the Maritimes Area. Currently the systems of Nova Scotia, PEI, and Northern Maine are radially connected only to New Brunswick as per Figure 6-3. This configuration makes New Brunswick the physical hub of the system. Even when considered on an integrated basis, this interconnected system is still small by comparison with other systems in the Northeastern US and Central/Eastern Canada. This small system size creates challenges in achieving economies of scale both in organization size and generation unit size.

Figure 6-3 Interconnections in the Maritimes



New Brunswick

Among the Atlantic provinces, New Brunswick has been the most ambitious in restructuring its electricity sector, with the creation of an independent system operator and the corporate restructuring of NB Power, albeit under a single holding company (a crown corporation) but with separate governance under separate boards of directors. New Brunswick has also moved furthest in the creation of market infrastructure and establishing retail competitive scope (comprising its transmission-connected large industrial consumers) as well as wholesale opportunity. However, the vast majority of end-use consumers still receive supply from a monopoly distribution utility and the vast majority of the power transacted in the wholesale marketplace is bought by the incumbent provincial distribution utility. As well, the future direction of electricity policy is in some doubt as the recently proposed sale of most of NB Power contemplates that "The regulatory framework governing the generation, transmission and distribution of electricity in New Brunswick will be altered to conform to the framework currently in effect in Québec."[5]

The present New Brunswick market adopts the bilateral market construct envisaged in FERC Order No. 888, with a system operator independent of market participants (per FERC Order No. 889) and with elements of competition and dispatch optimization that are normally part of pool markets (e.g. Alberta, Ontario and US ISOs). This more than meets the standards necessary for reciprocal access to US markets.

By virtue of its position at the regional hub, and of the lead taken by New Brunswick in restructuring, the New Brunswick System Operator (NBSO) has naturally taken something of a lead role in regional issues. It is the Reliability Coordinator for the region, and is providing OASIS service to NSPI. NBSO has also been working in close cooperation with ISO-NE, the system operator for New England, towards greater harmonization of both markets in order to facilitate trade and improve reliability. The potential sale of NB Power contemplates that "All functions of the NBSO, as well as the assets and employees of the NBSO, will be assumed by [New Brunswick transmission company owned by Hydro-Québec]……"[6]

Prince Edward Island

The power system in Prince Edward Island is mostly owned and operated by Maritime Electric, and is strongly linked to New Brunswick. In terms of market structure, the PEI system effectively exists within the competitive market context of the New Brunswick System. Maritime Electric is not required to participate directly in NPCC, but is required to meet those standards relevant to its interconnection with New Brunswick, and to support NBSO in exercising its reliability-related responsibilities. The Regulator approved in 2008 an Interim OATT for Maritime

[5] October 29, 2009 Memorandum of Understanding between the Government of New Brunswick and the Government of Québec, section 3.1 (b)
[6] ibid, section 3.1(a)

Electric and they also have Standards of Conduct which prescribe processes and behaviours for Transmission staff and those in their Energy Control Centre.

Newfoundland and Labrador

The Newfoundland and Labrador electricity system needs to be considered as two separate systems plus a number of rural isolated sites. The Island Interconnected System serves most communities on the island, but has no interconnection with other systems. The Labrador interconnected system serves principal communities in Labrador, and is interconnected with Hydro Québec through the high voltage transmission lines from Churchill Falls. NALCOR, a provincial crown corporation which acts as a holding company, owns and operates the Labrador system and through its operating subsidiary Newfoundland & Labrador Hydro (NLH) most of the Island transmission, and 80% of the island generation. NLH also provides all distribution in Labrador and rural distribution service on the island. Newfoundland Power (a subsidiary of investor-owned Fortis) operates some generation on the island and provides distribution service to most customers on the island. The operations of NLH and Newfoundland Power are thus complementary rather than naturally competitive. Competition is likely to be in the form of "competition on entry" through RFPs issued in respect of new renewable or other supply. Neither NLH nor Newfoundland Power is required to participate in NERC nor NPCC, whose standards are designed as applicable to the interconnected bulk power system. However, NLH has elected to become a member of NPCC.

New England

The Independent System Operator in New England (ISO-NE) was created in 1997 in response to FERC Order No. 888 and its intention to increase competition in electricity markets. It consists of 13 interconnected sub-areas. ISO-NE superseded the previous pool NEPOOL as the region's system operator, and since 2000 is also in charge of the New England Regional Transmission Expansion Plan (RTEP) process. The RTEP is a planning process that integrates market response with needed reliability and economic transmission upgrades.

In 2003, ISO-NE significantly enhanced the wholesale market it serves by implementing a market design modeled after the one in PJM (the RTO serving large areas of Pennsylvania, New Jersey and Maryland). The market includes a two-settlement system (day-ahead and real-time), locational marginal pricing (LMP), auctions of financial transmission rights, and installed capability requirements. In 2004, ISO-NE was recognized by FERC as an RTO.

The development of the New England market has demonstrated the importance of three main themes: utility restructuring, congestion, and generation resource adequacy.

Prior to the establishment of ISO-NE, the degree of utility restructuring in New England varied by state. Massachusetts, Connecticut and Maine all required or strongly encouraged their integrated utilities to divest generation assets and become exclusively distribution and transmission operators. On the other hand, Rhode Island, New Hampshire and Vermont only required functional separation of generation from transmission and distribution.

Until 2003, the ISO-NE energy market operated under a uniform energy market clearing price for all loads and generators (similar to Ontario and Alberta). Generators dispatched “out of merit” to serve a local need would get a constrained-on payment (above the prevailing market price) recovered from all consumers through an uplift charge. In the early years, congestion payments were minimal, but grew steadily and became a major burden. The introduction of Locational Marginal Prices (LMPs) was in part a response to this problem.

The mechanism for generation resource adequacy in New England has been an Installed Capacity (ICAP) requirement placed on wholesale customers and load serving entities (entities that have a statutory obligation to supply customers who choose not to purchase supply in the competitive market). However, the simple ICAP proved to be an inadequate guarantee for local adequacy in the presence of transmission constraints which resulted in high uplift costs and high payments for “reliability-must-run” contracts with critical generators. A new locational-based forward capacity market (FCM) is currently being phased in.

6.2 Potential for Evolution

6.2.1 Stakeholder Concerns

The stakeholders providing input to the study are dominantly suppliers or potential suppliers as contrasted to users of electricity. This is a typical feature of all dialogues that accompany potential changes to electricity policy. This requires government, regulatory and other public-purpose agencies to make special efforts to reflect the needs of users of electricity, if the objective is to balance both supply needs and user interests. In compiling this report particular effort was put into meeting with groups representing electricity consumers’ interests, but in those cases where meetings were arranged, the discussions focussed more on supply issues rather than user issues. As might be expected, the concerns outlined related to the difficulties encountered by potential developers of independent generating plants.

The general complaint is that NSPSO is hampered in its ability to act independently of NSPI. Stakeholders go on to suggest that the solution to this problem is to establish the NSPSO as a stand-alone entity separate from NSPI. Specific instances of decisions or actions being compromised by a lack of independence were not offered. The NSPSO group within NSPI confirmed that they had heard the same comments over an extended period of time, and also had been unable to elicit any specific examples of their failure to act independently.

The lack of specifics is consistent too with stakeholders’ view that the NSPSO group at NSPI are highly professional and with high ethical standards. The NSPSO indicated that they too, had received that assurance from stakeholders and that it was a reputation that they had worked hard to earn and continue to focus on maintaining. For example, the functional arrangement within NSPI conforms to FERC requirements for system operator independence for US entities, which includes the provision of an internal compliance officer. As well, NSPI has formal policies and practices which ensure there is no intentional or inadvertent transfer of information which would give NSPI wholesale merchant functions and affiliates any commercial advantage over other market participants.

Under this general lack-of-independence concern, two slightly more specific complaints were voiced. The first is the lack of a Nova Scotia champion for market evolution and the view that this is a role of the NSPSO. The NSPSO group confirmed that their activities in this regard are conditioned on NSPI and Emera's corporate strategies, but also point out that they comply with their mandate as it relates to working on behalf of those connected to the Nova Scotia electricity grid. Specific examples include representing Nova Scotia interests in the several regional organizations that exist to exchange views and improve coordination on matters ranging from system operating rules to long range capital planning. Stakeholders had no specific instances to cite where the NSPSO had failed to be a champion, but this would be a little like trying to prove a negative. So the concern remains one of a general feeling that there is not enough effort being put into leading market evolution.

The second more specific complaint related to the slow pace of progress toward getting more independently owned generation on line. This breaks down into frustration with two processes – the process by which projects are selected for entering into a contract with NSPI and the process dealing with the system connection aspects of the selected projects carried out by NSPSO.

Again, stakeholders didn't offer specific examples of particular assessment delays, but the feeling remains among stakeholders that worthwhile projects, which are necessary to meet the policy objectives of government, are being delayed through slower than necessary selection and connection assessment processes. Given the NSPSO's central role in planning the system and assessing the arrangements for connecting new suppliers, stakeholders suspect that the independence of the NSPSO is a significant factor to their concerns. Stakeholders perceive the limited independence of the NSPSO from the owner of the transmission facilities, and from the dominant generator using the system, as factors contributing to the difficulty for independent generators to implement their projects.

This complaint appears to be consistent with concerns expressed by stakeholders in other jurisdictions where open system access provisions have been introduced. Discussions with the NSPI Transmission group, and separately with the NSPSO, indicate that the circumstances and practices in Nova Scotia are similar to those for many other systems.

Like most systems that have moved from being a vertically integrated, centrally planned system to an open access system without any significant changes to the transmission infrastructure, the Nova Scotia system is pretty much right-sized to its current customer and generator bases. The system was never intended, for example, to integrate wind power for export. The physical and operational limits of the existing system create constraints for connecting new generation. These constraints are magnified by the need to avoid setting precedents which cannot be maintained in a fashion that is fair and transparent to future new generation. What may seem as intransigence to applicants is at least partly the result of the NSPSO exercising appropriate due diligence to protect the interests of existing system users, and ensure future rationality.

While the time taken for connection assessments is dictated to some extent by a shortage of qualified people to do the analysis, the NSPSO follows common practice in other jurisdictions of contracting out most of the analytical work. This leaves the actual decision-making process to the NSPSO who, of necessity, follows the dictum “first, do no harm” to the existing system users.

In summary, there is a widely held view that the NSPSO should be more independent but this view is supported by evidence that is more general and circumstantial than it is specific and direct.

6.2.2 Nova Scotia Electricity Policy

As discussed in section 6.1.2, Nova Scotia’s restructuring objective of levelling the playing field for all businesses and residents effectively became a policy of levelling the playing field for independent suppliers of electricity. This is because the vast majority of end-users of electricity already see a playing field that is level with their counterparts in neighbouring provinces. This supply-side orientation of restructuring objectives is further underlined by requirements put on NSPI to purchase new supply requirements through competitive tendering processes and, in the case of renewables, not consider any tender from an NSPI affiliate.

The practical interpretation of the policy objective of the 2005 restructuring in Nova Scotia seems therefore to be to ensure that the cost of electricity to consumers is controlled through competitive procurement in a wholesale market. This puts independent power producers based in Nova Scotia on the same footing as their counterparts in neighbouring provinces and states, in that they have opportunities to supply local needs as well as having open access to external markets.

6.2.3 Changes in Regional Context

More recently, Nova Scotia’s original electricity policy has taken on some additional urgency and texture with the overlay of policies to reduce the carbon footprint of electricity through increased use of renewable energy. While other renewable sources exist and should be developed, in the aggregate, it is expected that wind, tidal and biomass generation will dominate the in-province supplies of renewable generation. The significant feature of wind and tidal is that both are intermittent and uncorrelated with hourly or seasonal variations in electricity use. While tidal energy is predictable to a much greater degree than wind, tidal power doesn’t offer diversity between geographically separated sites to the extent possible with wind.

The promise that the statistics of diversity will reduce the effects of intermittency, or reduce the cost of accommodating it, lies behind a view that a regional approach to renewable energy will have advantages over a collection of provincial approaches. Regional scope takes on greater significance when it is recognized that increasing exports to neighbours seems to be a part of the electricity strategy of every Atlantic province. New Brunswick is pursuing the opportunity of becoming an energy hub, Prince Edward Island sees opportunity in developing its early-mover position in wind generation by being a major exporter, and Newfoundland and Labrador is pursuing energy markets in and south of the Maritimes. Some aspects of the potential merger of Hydro-Québec and NB Power, such as the elimination of an independent system operator, seem to be at odds with the energy hub policy, and the transaction is therefore a significant wild card. These separate initiatives have the potential to destructively collide or constructively reinforce each other.

The constructive potential of regionally coordinated action has long been recognized and exploited by various entities involved in the Maritime and New England electricity industry. Well before restructuring, vertically integrated utilities in New Brunswick and Nova Scotia made mutually beneficial arrangements through a number of working-level committees dealing with such things as system planning and system operations. In fact, one stakeholder observed that the level of regional cooperation appears to have declined in recent years coincident with the move toward "open" access markets.

Still, it remains true today that the power systems in Nova Scotia and New Brunswick, through their respective system operators, are planned and operated on as close a relationship as exists anywhere in Canada. For example, it is rare for adjacent systems to share operating reserves to the extent which Nova Scotia and New Brunswick do. This provides permanent ongoing savings to customers in both provinces. In the past, the commissioning dates of new generating units at Tuft's Cove (Nova Scotia) and Coleson Cove (New Brunswick) were coordinated so that customers in both provinces realized savings from having regional generating capacity increase in several relatively smaller steps rather than fewer larger steps.

Offsetting the clear technical and economic advantages of adopting a regional approach to electricity are the equally clear existing and historic realities that have their roots in the fact that each province is a separate political jurisdiction. Over time, this has resulted in different laws and policies in the provinces and, in turn, those differences will result in wealth transfers in both directions if electricity arrangements were harmonized. In the years and decades following harmonization, the wealth transfers would dissipate in relative terms, and would be overwhelmed by the regional economic benefits, but concern about the immediate impact is often enough to chill progress toward integration.

Opportunities from a regional approach require interties between the separate provincial and state transmission systems. And while the physical facilities must be in place with adequate capacity, the way that capacity is allocated and reserved is also critically important to facilitating a regional approach. For example, while the physical capacity of the interties between New Brunswick and Maine has recently been increased, all of the incremental capacity has been reserved long-term by Hydro-Québec. And since most of the pre-existing capacity was already reserved by NB Power, the additional physical intertie capacity does not create opportunities for balancing wind resources over wide areas, nor for developers to participate in a regional market. Should the potential merger of Hydro-Québec and NB Power materialize, it will concentrate ownership of intertie capacity reservations in even fewer hands.

While the rules do provide for the re-auctioning of reserved transmission capacity that is not in use, such secondary market capacity is not as firm as in the primary market, and consequently is not as useful in entering into long term supplier-customer contracts which are often necessary to support new generation investment. Also, the rules require what in effect might be periodic reopening of capacity reservations. However, for good reason, the outcome of any such reopening is biased in favour of incumbents retaining their rights.

These circumstances are not unique to the New Brunswick – Maine interconnections. Market participants report similar experience with BC Hydro dominance in accessing the British Columbia – Washington interconnector. As well, the new Ontario – Québec intertie has been fully contracted by Hydro-Québec, thereby eliminating any opportunity for third parties accessing the Ontario market on a firm basis via the Québec transmission system.

A final factor significant to the potential for a more regional approach to electricity is highlighted by recent comments by the Premier and Minster of Energy in New Brunswick. The comments related to the government's expectations that New Brunswick would earn revenue by acting as an energy hub and specifically in the wheeling of electricity on the New Brunswick transmission system. At issue is the way the cost of transmission services is calculated and recovered from users.

At present, each provincial and state system calculates costs and recovers them on a per unit basis from all users. As a service with regulated pricing, the rates charged are intended to cover only the actual operating costs incurred by the system owner plus a charge related to capital investments. The profit for the system owner is incorporated in the return on the investment or "rate base" which is a part of this carrying charge. Since each system is treated as economically independent of the others, a transaction which spans more than one transmission system incurs a separate charge for each system involved. This "pancaking" of transmission charges has the effect of making in-province transactions more economically attractive than ones involving an import or export that is otherwise similar.

Favouring the home market has its benefits but it also creates silos and undermines prospects for a regional approach to integrating renewable energy. Pancaking of transmission charges will be an impediment to regional balancing of renewable intermittency and therefore represents a potential cost to all regional players – including the province hosting imports, exports and through traffic. Stakeholders mentioned pancaking as one of their major economic difficulties when considering investment in new generation based in Nova Scotia.

6.2.4 Potential Changes in Commercial Structure

It is apparent that commercial factors beyond Nova Scotia's borders will limit any unilateral attempt to meet provincial renewables targets through a regional approach. For example, taking advantage of geographic diversity to lessen the intermittency effects of wind power requires sufficient intertie capacity being set aside to accommodate the fluctuating flows resulting. Another example is the potential to import power from Newfoundland & Labrador's Lower Churchill project which will only be attractive to NALCOR if the transmission arrangements are part of a broader initiative for them to access the New England market.

The following outlines some of the potential changes to the regional electricity structure that would facilitate Nova Scotia's renewable energy objectives being met in a regional context. Most require some degree of shared vision with one or more regional partners.

(a) Regionalizing Wind Integration

Since it is relatively new and there is a clear advantage to all participants to access geographic diversity, it may be possible to establish a new regional electricity initiative that relates solely to wind. This new wind energy sector would be a cooperative of the participating provinces and ride above the existing provincially-based electricity sectors and lease transmission and other services from them. In effect, a *virtual* regional electricity system operating on space set aside on each of the *real* provincial electricity systems. Within each province, the selection of the participants and the setting aside of the system capacity would be left as a provincial matter but all participants would invest and operate in accordance with regional policies and rules.

This cooperative would in effect be a marketing organization delivering wind-generated electricity in the amounts requested to each of its provincial members at a price determined from purchasing that energy on a regional basis. It would access and pay for use of transmission infrastructure on each of the systems involved according to the standard tariffs already in place. It would also purchase/sell any balancing energy necessary to bridge the difference between contracted deliveries and actual wind production. Again, these transactions would be done on a regional basis thereby accessing the most economical source/load for balancing.

To accommodate this, any federal laws related to climate change would have to treat relevant targets, caps credits and offsets as also being regional. As well, "dynamic scheduling" transmission tariff arrangements would have to be put in place on each provincial transmission system to allow the variability associated with wind power to be handled in the most economic way available to the cooperative. For example, it may be more economical to balance wind generation originating on PEI and being delivered to customers in New Brunswick with energy from a gas-turbine plant operating in Nova Scotia than to impose the balancing requirement on either the supplier or the customer.

This same dynamic scheduling is also key to taking advantage of geographic diversity of the intermittency since, in effect, intermittent wind in one place is being used to balance non-coincident intermittency in wind in another and flows on the transmission between them are clearly also going to be variable and unpredictable. Some progress has been made in this regard with the NBSO's recent introduction of just such a dynamic scheduling capability under the New Brunswick OATT.

When activities which are already established on a provincial basis are regionalized, there will inevitably be some transitional wealth transfers. But when brand new initiatives such as wind power are undertaken from the start on a regional basis, there is no transition so that the costs and benefits can be both optimized and allocated fairly and without disruption.

(b) Competitive Market for Intertie Capacity

As outlined in Section 6.1.1, all the electricity systems in the region are based on a bilateral contracting model which requires a system for market participants to arrange for adequate transmission capacity. At present, all transmission services in the region operate under similar OATTs which have as their central concept that transmission capacity is to be bought and sold in a competitive market. But at the same time, no attempt has been made to guard against one or more parties using their ability to dominate the market. This has little impact on intra-provincial markets since they are small and effectively single-buyer markets anyway. But a regional market is bigger and has multiple potential buyers and sellers, and it is therefore necessary to ensure that their ability to participate is not compromised by their inability to obtain transmission capacity.

Most immediately, the problem is at the interties where, repeating the previous example of the interties between New Brunswick and Maine, inadequate provisions to prevent the exercise of market power has allowed virtually the entire intertie capacity to be reserved in the long-term by just two entities – NB Power and Hydro-Québec. Should their recently reported potential merger proceed, the capacity could be held by a single entity.

On interties between systems, consideration could be given to enacting the same types of measures used in competition law to ensure that market power is not exercised. Such measures might include requirements that no one party can have a stake in more than 30% of the market, and that a minimum of 5 parties must participate in any competition before a situation can be considered as truly competitive. Such an arrangement might apply only to intertie capacity that is not related to consumptive use of electricity at one end or the other of the intertie. In other words, transfers to end-use customers being served by a system connected directly to the intertie could have priority.

In order to facilitate cross-border trade, the system of reservations of inter-tie capacity could also be simplified. For example, instead of making reservations on both sides of the geographical border under the rules of each system operator, only one of the system operators could be assigned responsibility for the reservations on a particular tie. Another possibility is that the total transfer capacity could be divided between the two system operators and auctioned separately. For most transactions this would result in dealing with only one system operator for the reservations.

(c) Transmission as a Public Good

To some extent, the impediments to a regional approach are exacerbated by the fact that each jurisdiction has deregulated as a move toward opening up their electricity supply systems to market forces. As mentioned above, this includes not only a competitive market for the electricity itself, but also for the transmission capacity to move the electricity around.

As described in Section 6.1.1, Alberta and Ontario have each adopted the pool model for the real-time electricity market. Since this model requires all short term transactions to be coordinated by a single system operator, transmission capacity is inherently assigned and there is no need for a competitive market for transmission capacity. In effect, this approach treats transmission capacity as a public good instead of a market good. Under these arrangements, transmission is built in accordance with a long range plan developed by a central agency such as the system operator.

In contrast, the bilateral contract model requires that transacting parties acquire rights to appropriate transmission capacity before their transaction can be given effect through actual dispatch. Under this arrangement transmission expansion tends to be oriented towards satisfying the needs of specific market participants within, and sometimes from outside the province, and the results will not necessarily respond to the interests of the consumers.

Since transmission development typically has a longer lead time than generation development, the public good approach has the added advantage of ensuring that there is adequate transmission capacity available when it is needed. In contrast, the market based approach effectively requires that congestion costs exist before transmission can be built. The public-good approach will be biased toward over-investment in transmission whereas the market-good approach will be biased toward under-investment. To some extent at least, the excess costs of over-investment on the public-good model are offset by savings from reduced congestion charges and by lower electricity prices due to less constrained competition among generators.

The benefit to the government of Nova Scotia in considering the public-good model is that it allows more certainty in guiding electricity supply mix development than the market-good approach. For example, enabler lines can be extended into areas that are targeted for wind development, and wind generation developers will obviously favour those areas due to the ready availability of transmission capacity. As well, since the rights to using the transmission capacity are not available for sale, there is no concern that one or a few developers will lock up available capacity as a way of discouraging competition.

While the same development outcome could occur under the market-good approach, there would first have to be a backlog of commitments to pay for new transmission capacity and this raises issues of potential market power. The North American natural gas transmission pipeline system uses this approach but it is noteworthy that it also includes what are in effect public-good facilities such as the TransCanada pipeline which operates on a rate-regulated basis as a common carrier. The State of Alaska has also recently committed to a public-good open-access common-carrier approach for a new natural gas pipeline, precisely so that there will be strong competition between gas field developers confident that their route to market will not be blocked by competitors tying up all the outbound transmission capacity.

While this public-good approach is different from FERC's pro forma OATT, companies from both Ontario and Alberta have licenses from FERC to use US transmission facilities, thereby demonstrating that the approach meets FERC standards for reciprocal open access.

(d) Pancaking

"Pancaking" refers to the separate payment of transmission charges to each transmission system involved in a single power transfer. As mentioned above, it acts as a disincentive for importing or exporting and thus undermines the prospects of regional activities in general. Pancaking could be eliminated by adopting a single regional transmission tariff, but that would entail some relatively complex legal issues related to regulatory authority and oversight.

Alternatively, pancaking could be eliminated by the adoption of a "license plate" concept whereby each transfer pays only once on its originating transmission system in order to use the entire regional transmission system. The "license plate" analogy is obvious in that motorists with a license plate bought in any province or state in North America are allowed to use the road system in all provinces and states. With roads, the economics are somewhat different than with electricity transmission in that each vehicle uses up only a tiny fraction of the available road capacity, whereas each electricity transfer is typically a significant fraction of the available transmission capacity.

Of course there would be transfers of wealth between provinces if such a license plate system were adopted as simplistically as described above. This could be mitigated by a certain amount of regional revenue pooling, whereby part of the transmission revenue collected in each province is pooled and distributed among the provincial systems in proportion to the volume of their through traffic. Before deregulation of the telecommunications industry, such a system worked for many years with respect to long distance telephone charges, where the pooling and distribution was handled by TCTS, the TransCanada Telephone System, a cooperative owned and staffed by member telephone companies from across Canada. Telephone users paid a single long distance charge to their local company even though they might effectively be using the facilities of many companies.

6.3 System Operation Scenarios

This section describes the four different possible scenarios for the evolution of the system operator in Nova Scotia, including the scenario to remain as it is today.

6.3.1 Current Functionally Unbundled NSPSO

As described in greater detail in Section 6.1.2, under the current arrangement, the Nova Scotia Power System Operator functions as part of the NSPI Customer Operations Division. NSPSO carries on its obligations following the standards of conduct approved by UARB, ensuring that market sensitive information is not intentionally or inadvertently shared among other groups within NSPI, particularly the transmission and the wholesale merchant groups. The roles and responsibilities of NSPSO are defined in the Market Rules and include the reliable and safe operation of the bulk electrical system, operation of the wholesale market, administration of market rules, reliability and system planning, administration of the OATT and the GIP.

6.3.2 Independent NS system Operator (NSISO)

A potential change would be to make the NSISO completely independent of any market participant and transmission owner. Depending on the governance structure, some representatives of market participants could be named as part of the management board, although Canadian practice is for boards to be composed of people completely independent of any market participant, and to use advisory committees as channels for stakeholder input. The day to day operations would be run by employees of NSISO who would be independent of NSPI, or any other market participant. Some resources may need to be transferred from NSPI to NSISO (e.g. specialized personnel, equipments, etc), and this may represent some difficulties given the fact that NSPI is investor-owned. As seen in New Brunswick, this transfer of resources to set up an independent system operator may take some time.

The NSISO would be created by provincial legislation and regulated by the UARB as a non-profit organization. The roles and functions of the new NSISO would be basically the same as in the current NSPSO, and therefore major changes to the market rules would not be required. However, internal standards of conduct around disclosure of market-sensitive information between NSPI business units would be simplified. Some previous agreements between NSPI and NBP (e.g. interconnection agreement) and between NSPI and other suppliers would need to be transferred to the NSISO.

6.3.3 NS/NB-ISO

This scenario considers the creation of a new entity responsible for jointly operating the bulk electricity systems and wholesale markets in both provinces. The Nova Scotia operator would need to be made independent of NSPI in order to be amalgamated with the already independent NBSO. Some arrangements would also have to be made for joint ownership and governance of the new entity, such as sharing in proportion to the relative size of the two systems, determined on the basis of installed generating capacity, electricity sales volume or some combination. The simplest mechanism would set the proportion by mutual agreement, with provisions for review and adjustment every 5 years or so.

The two balancing areas, currently separate, would be merged. This would imply a common dispatch for balancing the merged system. This would facilitate wind integration in both provinces by taking advantage of wind diversity over an expanded geographical area and reducing costs of balancing by making available a greater number of resources (i.e. system imbalances will be covered by the cheapest available resource regardless of which province it was in). However, a portion of the interconnection capacity would need to be reserved for balancing operations, and this may impact the already limited transfer capacity between the two areas. As well, provisions would have to be made to ensure that environmental emissions from generation in one province that is operating to balance wind generation in the other province are properly allocated. If emissions are priced either through a tax or a cap and trade scheme such as is contemplated for CO2, appropriate allocation could be achieved by simply including the emission costs in the cost of energy transferred.

Northern and Eastern Maine as well as Prince Edward Island are part of the New Brunswick System Operator (NBSO) “Balancing Area”. Although these systems are only radially connected to the NB system, for this option of a NS/NB ISO, in effect the transmission providers Maritime Electric (MECL) from Prince Edward Island and the Northern Maine Independent System administrator (NMISA) would also need to be involved in the discussions.

Although the New Brunswick and Nova Scotia wholesale markets are based on the same principle of bilateral transactions, combining both markets would require the drafting of a unique set of market rules, requiring detailed studies to resolve any incompatibilities. One such incompatibility might be the Fuel Adjustment Mechanism (FAM) in place in Nova Scotia. This mechanism is essentially a surcharge related to projected fuel costs that is established on a 6-month cycle and incorporates a deferral account which is reconciled over subsequent periods. Since it can result in post-transaction surcharges and rebates, the deferral account restricts the application of FAM to customers that receive electricity under regulated rates, rather than pricing determined from market transactions, and for this reason does not apply to NSPI exports.

The NS/NB-ISO, under normal conditions, would direct operations of the transmission systems in each province. The two transmission owners would remain responsible for physically implementing the control instructions on their respective system. Distribution system operations in each province would remain unchanged.

The choice of location for the new entity would need to be analyzed to determine the best alternative based on benefits and costs.

It is likely that a merger between Hydro-Québec and NB Power would eliminate the option of a merged NS/NB-ISO, since the transaction would result in the elimination of the NBSO as a standalone entity. But at the same time, a Hydro-Québec/NB Power merger probably enhances the prospects for a regional ISO, as outlined in the next section.

6.3.4 Regional ISO

Without a major change such as the merger of Hydro-Québec and NB Power, a regional ISO is a medium to long-term alternative. Many legal and regulatory issues would need to be discussed and agreed to before such a project could become a reality. As discussed earlier, some of the main drivers for the creation of a regional electricity market, of which this regional ISO would be part, are the expected increase in regional trade due to large regional projects (e.g. Point Lepreau II, Lower Churchill, large wind developments in PEI, etc.) and the need to facilitate the integration of wind and other renewable intermittent resources by taking advantage of regional diversity.

The province of PEI is already part of the balancing area controlled by NBSO. As discussed in previous sections of this report, different options are being considered for bringing power from the Lower Churchill project through Nova Scotia and New Brunswick. It is therefore conceivable that the regional market could be composed of at least the provinces of New Brunswick, Prince Edward Island, Nova Scotia, Québec and eventually Newfoundland & Labrador.

Due to the increasing amount of physical exchange between the New England (Maine) and New Brunswick systems, the NE-ISO has been working in close cooperation with NBSO towards greater harmonization of the two markets, in order to facilitate trade and improve reliability. Furthermore, given that many generation projects being developed in the Maritime region and Newfoundland & Labrador are targeting the New England market for a significant share of their production, a long-range vision may involve a regional ISO that embraces both the Canadian Atlantic provinces and New England. However, the legal and regulatory obstacles involved in an international ISO such as this would be much more difficult to resolve than those for a “Canadian-only” regional ISO.

For this study, we are considering that the most likely scenario for a regional ISO would include the provinces of New Brunswick, Prince Edward Island and Nova Scotia. If the decision is made to evacuate all or part of the output from Lower Churchill via New Brunswick and Nova Scotia, and some of this output is sold in these provinces, then Newfoundland & Labrador could also be part of the regional ISO. A merger of Hydro-Québec and NB Power would enhance the prospects of Québec being a part of the regional market, but given its large size relative to other participants, its involvement would significantly affect the overall approach.

6.4 Evaluation of Options

This section develops the evaluation criteria to be used in the assessment of each of the four options for system operator, as described in the previous section. The criteria have been developed based on the requirements of the terms of reference, the consultations with the stakeholders, and the consultant's experience with sector reforms in various jurisdictions.

The first three criteria (independence, market leadership and reduced cost of supply) are related to "benefits" or "opportunities" and the last two (legal regulatory requirements and set-up costs) are related to the idea of "costs" or "challenges".

Each option for system operator is then discussed based on the five criteria. No attempt has been made to quantify the criteria. The analysis is based on a qualitative judgement using four grades (poor, fair, good, best) for the benefits and four grades (low, medium, high, very high) for the costs.

6.4.1 Evaluation Criteria

1. Independence

The system operator, in its role as provider of non-discriminatory transmission access to third parties, must act independently of any interest of generators, distributors or marketers. As discussed above, FERC in Order 888 did not require a legal separation of the system operator from other functions of the vertically integrated utilities, but only a functional separation under strict adherence to standards of conduct to avoid transfer of market-sensitive information. However, in subsequent RTO Order 2000, it was required that the new ISO/RTO be a separate legal entity. While there is no requirement for Nova Scotia to comply with FERC orders, as for all electricity systems in the region that has been the practice to date.

Independence of the market operator becomes indispensable when it comes to the functions of administration and enforcement of the market rules and running of the different markets (day-ahead, real time, reserves, transmission rights, etc.) in a transparent and non-discriminatory fashion.

Also, as the System Operator is required by the market rules to perform system planning functions for the generation and transmission systems, its independence from generation companies is an important consideration in the evaluation of the options.

Independence is not an absolute but is rather a matter of degree. For that reason, there is no right or wrong level of independence, but clearly the greater the degree of independence, the less likely it is to be called into question.

2. Market leadership

Although general policy about market structure, market design, mitigation of market power, renewables and others is the responsibility of governments, the system operator (in its capacity of market facilitator/operator) needs to play a leading role in drafting, amending and enforcing the market rules, monitoring the behaviour of participants and, in general, making sure that the competitive market is functioning properly. In some cases, the regulator can also be an important market champion, but it will always need to be supported by the system-specific know-how and information provided by the system operator. The market operator must also be "visible" to the stakeholders and to the public in general by maintaining a well structured web-based market information platform, holding periodic information and training sessions, and being present at major industry conferences and policy discussions at the local, regional and international level.

A prerequisite to exercise this leadership is the indifference of the system/market operator to the commercial outcomes of the market. This criterion is therefore related to the "independence" described above.

3. Impact on minimized costs of supply

This criterion includes impacts on minimizing costs of supply of electricity, costs to procure resources to meet the desired reliability, transaction costs, cost of facilitating security of supply and cost of meeting GHG reduction targets. Enlarging the size of the system operations area has positive impacts on each of these cost categories.

Enlarging the electrical system controlled by the system operator should bring a reduction of costs in the supply of electricity, by providing an expanded choice of options for system dispatch, congestion management, provision of operating reserves, regulation, balancing, contingency management and reactive support. Other cost savings include the reduction of redundant functions in the enlarged/merged organization.

Although the current system of multiple provincial system operators in the Maritimes region, each compliant with NERC/NPCC reliability standards, has so far provided the desired reliability levels, enlarging the ISO area should make the procurement of the required resources more efficient, thus reducing the costs.

Merging control areas has another advantage in reducing costs since each area no longer would be required to independently maintain the balance of generation, load and exports/imports. This responsibility would belong to the new merged-area balancing authority. All generators providing regulation in the enlarged single area will be controlled by a single AGC (Automatic Generation Control – an automated system that acts to continually adjusts the production from selected generators on a real-time basis) function.

As the system operator area is enlarged, a reduction in transactions costs is expected for trade crossing several provincial/state borders. This is based on the assumption that the problems presented with rate pancaking are properly addressed and the mechanism for transmission reservations is simplified and managed in an economically efficient manner.

Facilitating trade across political borders also enables greater flexibility to meet provincial targets for security of supply and targets for GHG reductions (although this improvement would have to be supported by a corresponding regional approach to GHG targets and allocation of credits).

4. Legal & Regulatory Requirements

This criterion is used to weigh the legal and regulatory complexities involved in the creation and proper operation of the different system operation options.

When the option of separation of NSPSO from NSPI is contemplated, legal issues emerge by virtue of its current ownership and governance, since NSPSO is presently owned and staffed by an investor-owned entity.

Moving from a provincial to the simplest form of regional system operator (joining NBSO and NSPSO) moves the “footprint” across provincial lines, and this adds regulatory jurisdictional and legal issues that must be addressed.

From the examples in the U.S. related to the formation of RTOs, it is clear that some form of regional regulatory entity could be implemented to monitor and control the RTO and create the legal environment in which this regional operator would function. As well, the example of New Brunswick and Nova Scotia jointly regulating long-distance bus services also indicates that a single regulatory regime can cover neighbouring provinces without undue complexity.

5. Revenue requirements

These costs include the preparatory studies, direct and indirect cost of setting up each of the options (the costs of the current NSPSO are known through the NSPI rate applications) plus the annual recurring operating costs. However, no attempt was made to establish an exact budget for each of the options, but rather to establish a relative comparison between costs for the current option versus the others.

Depending on the path of the transition starting from the status quo, the start up costs can vary. For example the costs incurred in moving from the current SO organization to Option 2 and then to Option 3 will be higher in total than if the transition is made directly from the status quo to Option 3 in one step.

Option 2 (Independent NS System Operator)

For the creation of an independent NSISO, the costs to be considered include the requirements for additional administrative personnel and a separate management structure. Other additional costs relate to the potential transfer of personnel who may be eligible for severance costs if the change to independent status is deemed to constitute constructive dismissal. There could also be costs related to pension plans and benefits being transferred to the new organization. While it can be assumed that only minimal additional hardware/software is required, the existing system control infrastructure is in fact the property of NSPI, who would have to be compensated for it, and possibly also for the lost opportunity of future earnings related to its ownership.

The diagram below shows the relative scope of NSPI Control Centre (NSPI CC) in comparison to what is conventionally considered to be a "System Operator" – i.e. NERC definition – carrying out functions such as: dispatch instructions, system planning, reliability coordination, balancing authority, transmission operations[7].

The Control Centre is the item of cost representing the functions of system operations in the revenue requirements to UARB. The most recent revenue requirement application of NSPI (filed May 27, 2008) shows the forecast value for this item for year 2009 as $6,829,000.

The Control Centre is within NSPI's Customer Operations group which provides services to residential, commercial and industrial customers across Nova Scotia. The Customer Operations group includes: Regional Operations (transmission and distribution field operating groups), Transmission and Distribution Assets (asset management – inspections, planning and engineering, fleet and vegetation management), the Ragged Lake Control Centre (System Operator function) and Administration.

Today NSPI CC performs some functions which a typical SO does not (e.g., distribution operations, telecoms operations, protection & control engineering) and others which a typical SO does (e.g., system planning, administrative functions).

Currently some administration costs of NSPI CC such as: Financial, IT, Legal, HR, Corporate Governance, Maintenance & Operations of facilities are paid for by other branches of NSPI. Therefore the budget of a separate NS ISO's would need to include these items.

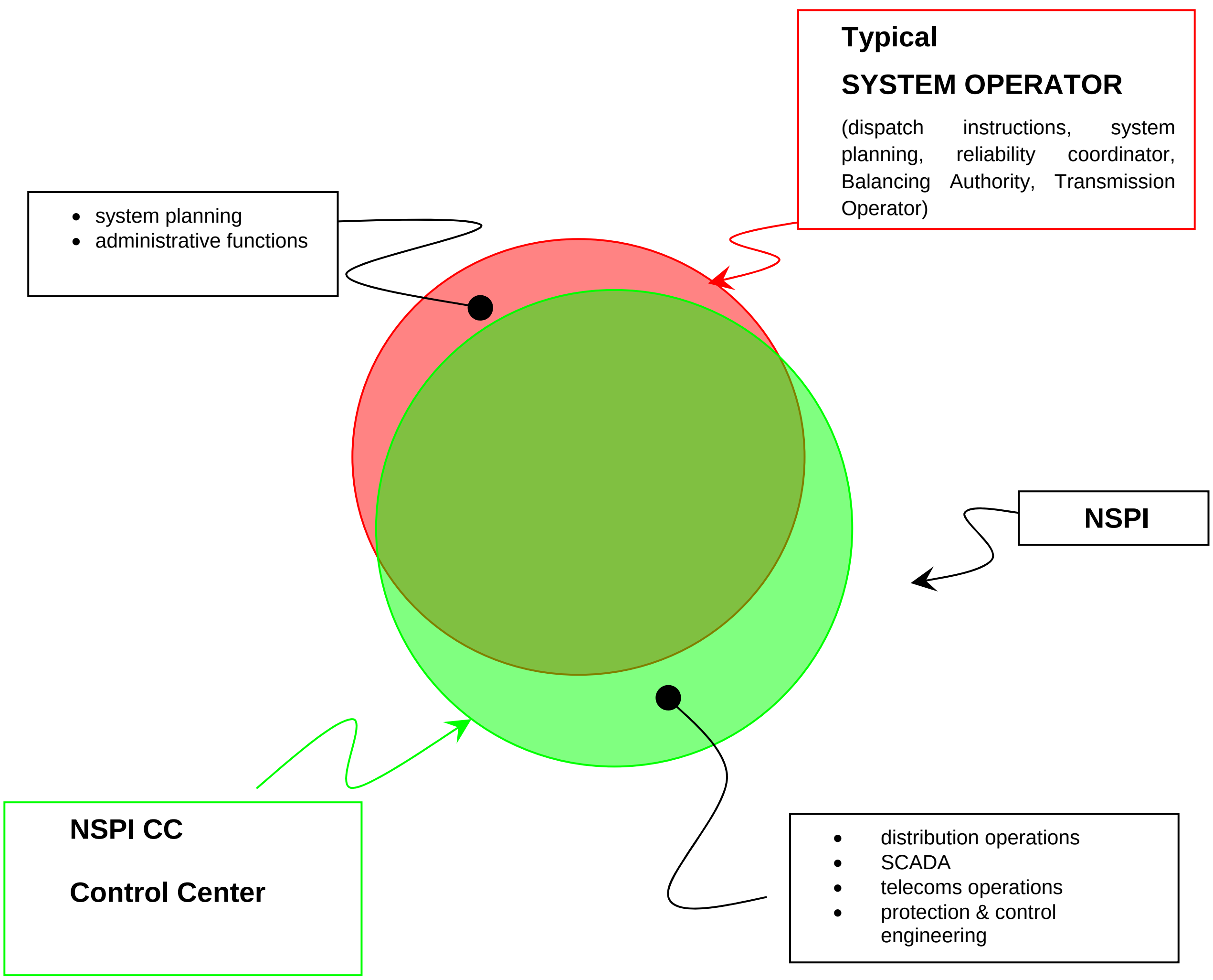
The OATT tariffs have been designed such that the revenue requirements for Operation, Maintenance & General costs of NSPI CC's are covered by the "Scheduling, System Control and Dispatch" service (Schedule 1 of OATT). It is important to note that all capital cost items (e.g., depreciation, return on equity, taxes, interests, etc.) of assets used by the Control Center are paid by other branches of NSPI and they are included in the OATT tariffs for transmission service (Schedules 7,8 and 10 of OATT). These assets include the back-up control centre. For a separate NS ISO these items need to be added to the budget.

[7] Transmission operations is a function that the Transmission Owner/Operator typically delegates to the System Operator since it saves the extra costs of having two separate control and supervision centers.

In separating NS ISO, some functions currently performed by the NSPI CC such as distribution operations, telecoms operations, protection & control engineering would need to be transferred back to the transmission and distribution groups of NSPI.

SO activities are highly integrated within NSPI with many people (10 – 20) undertaking both SO and NSPI activities, in some cases, e.g. financial person, they spend little more than 1 day per week on SO activities. Separation of SO from NSPI therefore may require a detailed review of organizational structure in both the new NS ISO as well as in NSPI. As such it will be both complex and expensive, and for both organizations will result in either (a) additional hiring or (b) contracting/seconding staff between SO and NSPI (thereby undermining at least some of the rationale for separation).

Just to illustrate the revenue requirements of a typical SO in a similarly-sized system it is worth mentioning that the New Brunswick Energy and Utilities Board approved (on an interim basis) the revenue requirement for year 2009-2010 for the New Brunswick System Operator in the amount of $10,234,000. This amount is still pending the Board's review of the liability for costs arising from the unfunded pension liability for seconded employees.



Option 3 (Joint NB/NS System Operator)

When compared to the cost of the independent NSISO, setting up a joint NB-NS system operator may bring some reduction in the costs of personnel due to elimination of certain redundant functions. However, these savings are likely to be offset by additional costs related to new hardware/software, communications and coordination with the two provincial transmission owners.

The existing SCADA systems (which interchange data and control signals between field equipment throughout each province and the respective central control room) of NS and NB are incompatible, so any amalgamation for regional SO would probably result in a new Dispatch Centre being established and the two existing Control Centres becoming the places where instructions from the Dispatch Centre are implemented.

Option 4 (Regional ISO)

Costs of setting up a Regional ISO are difficult to estimate, since they are highly dependent on a number of factors such as geographic location, market type, software/hardware and communication requirements. These costs will be shared in some fashion by the participating provinces/states. FERC carried out a study in 2003 in which the costs of forming a “basic” RTO were assessed for various jurisdictions. The basic RTO functions included open access transmission service, scheduling authority and available transmission capacity (ATC) determination, redispatch for congestion management, ancillary services, planning, parallel path flow mitigation, interregional coordination and market monitoring. The average annual operating expenses were estimated as 0.02¢/kWh, or less than 0.3% of the customer’s total bill. These costs do not include other market functions such as bid-based, security-constrained economic dispatch, unit commitment, locational prices, financial transmission rights or capacity markets.

A summary of the analysis of the four options for system operator against these criteria appears in Table 6-1.

Table 6-1 Tabulation and Commentary on Evaluated Options

Option	1-Independence	2-Market Leadership	3-Impact on reduced costs of supply	4-Legal & regulatory requirements	5-Revenue requirements
1-Current functional unbundling NSPSO	Fair – Standard of conduct is in place and no specific complaints have been raised. However, as the number of IPPs expands more customers eventually become eligible; this model presents an obstacle to market development. As more IPPs come to Nova Scotia the system planning functions of NSPSO may need to be reviewed to ensure non-discrimination.	Poor – Under current structure NSPSO lacks the mandate of acting as market champion. Market advancement initiatives would be seen as influenced by private investor's interests.	Fair – Current arrangements with NB achieve certain efficiency through sharing of reserves and responsibility for proportional share of regional interchange balancing with New England.	No changes needed to maintain the status quo	No changes needed to maintain the status quo
2-Independent NS System Operator	Good – Separate entity will work independently of market players	Good – Independence of market participants is a requisite to be a market champion. ISO would need to work on improving visibility in the market (web-based information platform, training for market participants, active in public forums). However, advocacy will be conditioned by Nova Scotia's interests which may not be the interests of all market participants.	Fair – Similar to the status quo	Medium – NSISO would need to be created by provincial law. Other issues would need to be resolved: separation of a public-purpose SO function from investor-owned NSPI is more complex than splitting from a publicly owned provincial utility such as occurred in New Brunswick.	Medium to High – Incremental costs of additional administrative personnel and new management, but potential reductions in cost due to separation of distribution operations, telecommunications and protection and control functions. Compensation to NSPI for system control infrastructure and potential transfer costs for employees.

Option	1-Independence	2-Market Leadership	3-Impact on reduced costs of supply	4-Legal & regulatory requirements	5-Revenue requirements
3-Merge NB/NS ISOs	Good – Separate entity would be more independent of market players in both provinces than would be possible with separate provincial entities.	Good – Similar to above except advocacy will be less conditioned by the interests of either province alone and therefore likely will align more fully with the interests of market participants.	Good – Simplifies existing areas of joint operation such as area balancing with respect to New England and single AGC. Facilitates new areas of joint operation such as wind integration. Simplifies arrangements for having transactions between suppliers and eligible customers located in different sides of the border. Some intertie capacity would need to be reserved for joint balancing operations.	High – Need to address jurisdictional issues and roles of each provincial regulator. New set of market rules will affect all existing market participants to some extent but probably NS participants more than NB participants. Agreement between NB/NS ISO, NB Power and NSPI. Transfer of other agreements. Market rules from both provinces would need to be made compatible and eventually merged into a single set, requiring detailed studies	Medium – Some savings due to elimination of redundant functions will be offset by new needs of system control infrastructure. These would depend on choice of location.
4-Regional ISO	Best – Independent of market players in the larger region. Requires agreement by regional governments on a broader range of energy sector policies.	Best – This would be a first in Canada and due just to its dimension will attract attention. Facilitates realizing scales of economy in resource development due to increased size of system involved.	Best – Maximum reduction of cost of dispatch, reserve procurement, congestion management. Reduced cost of transactions across borders and increased opportunities for efficiently meeting GHG targets. Increased volume of regional trade improves security of supply.	Very high – Complex legal and regulatory issues to be resolved. If NE is included, international factors involve federal government and laws on both sides of border. However, experience with formation of RTOs in the US can help ease the process.	High – Although costs can be significant they would be shared among many participants. FERC estimates show very small impact on consumer bill (less than 0.3%)

6.5 Conclusions

With only generic cost estimates and relatively diffuse benefits, as well as a changing regional context, it is clear that further more detailed studies are required before committing to any change to the SO arrangements for Nova Scotia.

From the market perspective, IPPs have only a single buyer market in each Maritime province, and a transmission rights market at interties that is subject to the exercise of market power by a few large entities. The only competition that can occur in such a situation is therefore the “competition on entry” to build new generating plants for serving in-province needs.

The independence of the SO becomes more important as the regional market becomes more accessible to Nova Scotia, and because an independent SO will have objectives which are unconditioned by corporate ownership, it could champion regional market changes on behalf of Nova Scotia. This is a chicken-and-egg situation whereby an independent SO would build the value of its independence. Provincial interests can only be unambiguously represented by an SO that is independent of all market participants and has a mandate and governance structure that reflects the public interest.

As new players invest in renewable generation in Nova Scotia, the system planning functions (generation and transmission) currently performed by NSPSO may need to be reviewed, to ensure a level playing exists and that provincial interests are met.

Economies of scale mean that there will inevitably be some advantages to integrating system operations throughout the Maritimes and beyond. Option 3 (combining SO for NS and NB) or Option 4 (regional SO) could be the next steps after Option 2 (standalone NS SO), or each could be a direct transition from the existing Option 1. Much depends on whether or not what is effectively a merger of Hydro-Québec with NB Power goes ahead, and what the final details are.

While Option 3 has clearly been the objective of NBSO, and New Brunswick has adopted a strategic goal of becoming an energy hub, provincial representatives from New Brunswick have in effect defended the existing system of pancaked transmission tariffs, which undermines the value of Option 3. The proposed merger raises further questions about the future of the energy hub objective and therefore the feasibility for Options 3 and 4 from Nova Scotia’s perspective.

Possible impetus might come from one of the two major projects under discussion whose justification requires access to a regional market – expansion of the Point Lepreau nuclear generating plant, or a Maritimes routing for transmission from the Lower Churchill project in Labrador. Either of these projects will inherently involve discussions among several provincial governments, which could expand to include a regional scope for the electricity market and system operations.

In moving beyond Option 2, Nova Scotia would have to see some assurances of improved access to both supply and markets outside the province. While arrangements for transmission access are fundamental to any competitive electricity market, they become particularly critical when interconnections to neighbouring systems are involved. Transmission access and arrangements to prevent the exercise of market power through limiting transmission access therefore become increasingly important when considering moving beyond Option 2.

The high level objectives of Nova Scotia electricity policy appear to be:

a) ensure that the cost of electricity to consumers is controlled through competitive procurement in a wholesale market which puts independent power producers based in Nova Scotia on the same footing as their counterparts in neighbouring provinces and states, in that they have opportunities to supply local needs as well as having open-access to external markets, and

b) access through regional markets, both external renewable supplies and geographic wind diversity, to cost effectively meet target levels of renewable energy in the Nova Scotia supply mix, while facilitating the development and integration of renewable generation located in Nova Scotia.

These objectives can not be achieved unless, in addition to constructing the necessary transmission and interties, changes are made to the commercial arrangements related to accessing, reserving and paying for the use of those facilities. A range of potential changes have been outlined above, but none have been analyzed in sufficient detail to bring forward as a definitive recommendation. Each has some promise however, and our recommendation is to consider them in greater detail.

The concept of a regional wind initiative should be given priority not only because it deals directly with an immediate objective, but also because it potentially reduces the need or simplifies the requirements for some of the other suggested alternatives. Through similar logic, the next priority should be to consider whether to change to a public-good transmission concept. If that change were made, it removes the potential for market power concerns with respect to intra-provincial transmission capacity. In the same priority level would be assessing a license plate approach to mitigating pancaking. Finally, some consideration should be given to preventing the exercise of market power with respect to intertie capacity. The cow is already out of the barn with respect to most of the existing interties, but since more capacity will be needed and as existing reservations come up for renewal, it will be beneficial to go forward with a revised approach to allocating and reserving intertie capacity.

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